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Revised Outer Continental Shelf Orders Governing Oil and Gas Lease Operations

DEPARTMENT OF THE INTERIOR

Geological Survey

Revised Outer Continental Shelf Orders Governing Oil and Gas Lease Operations

Notice is hereby given that, pursuant to Title 30 CFR Part 250.11, the Chief, Conservation Division, U.S. Geological Survey, has approved the issuance of revisions to the Outer Continental Shelf (OCS) Orders for the following OCS Areas:

Gulf of Mexico
Pacific
Gulf of Alaska
Atlantic

Revised Area OCS Orders Nos. 1, 2, 3, 4, 5, 7, and 12 will be effective July 1, 1979. These Orders supersede the corresponding Orders currently in effect for the OCS Areas listed above.

During the development of the final version of these Orders, it was determined that the requirements for the Orders for the North, South, and Mid-Atlantic Areas were the same. Therefore, the requirements were incorporated into a single set of Atlantic Area OCS Orders.

OCS Order No. 5 supersedes the paragraphs listed below for OCS Order No. 8 for the Gulf of Mexico and for the Pacific Areas. The remainder of OCS Order No. 8 for these Areas remains in effect.

Area	Superseded Paragraphs
Gulf of Mexico	4 through 7
Pacific	2

Due to the development of the Platform Verification Program, it is necessary to revise extensively the previously published OCS Order No. 8 to reflect the implementation of the Program; therefore, a proposed revision of this Order will be published at a later date, with a solicitation for comments.

These Orders incorporate appropriate suggestions which were received in response to the solicitation for comments on the proposed National OCS Orders, which were published in the Federal Register on June 29, 1977, Vol. 42, No. 125, and August 25, 1977, Vol. 42, No. 165.

Due to the enactment of the OCS Lands Act Amendments of 1978, it will be necessary to review and revise existing rules and regulations relating to OCS Oil and Gas Activities. Since this review may have an impact on the concept of National OCS Orders, no further action will be taken to issue National OCS Orders at this time. During the development of National OCS Orders, the Department deferred issuing revisions to existing Area OCS Orders, pending issuance of National OCS Orders.

Many requirements were incorporated which improve the safety and antipollution precautions of the Orders. The Department has determined that it is in the public interest to incorporate these improved requirements into revised Area OCS Orders at this time. It is also recognized that some of these requirements will be reorganized and restructured when the existing regulations are revised to reflect the enactment of the Outer Continental Shelf Lands Act Amendments.

Comments were received from the following organizations:

Alaska Offshore Operators Committee
American Petroleum Institute
Atlantic Richfield Co.
Brown & Root, Inc.
California State Lands Commission
Cape May County Planning Board, New Jersey
Chevron USA, Inc.
Continental Oil Co.
State of Delaware
ENMET Corporation
Exxon Company, USA
Georgia Office of Planning and Budget
Global Marine, Inc.
Gulf Energy and Minerals Co.-USA
Herbert S. Hiller Corporation
International Association of Drilling Contractors
Interstate Natural Gas Association of America
Marathon Oil Co.
Massachusetts Secretary of Environmental Affairs
Mobil Oil Corporation
Natural Resources Defense Council, Inc.
New Jersey Department of Environmental Protection
Offshore Operators Committee
Glenn Paulson, Assistant Commissioner for Science, New Jersey
Phillips Petroleum Co.
Paul Purser, Professional Engineer
Shell Oil Co.
Sun Production Co.
Texaco, Inc.
Texas Eastern Transmission Corporation
The Offshore Co.
Trans-Continental Gas Pipeline Corp.
U.S. Coast Guard
U.S. Department of Commerce
U.S. Environmental Protection Agency
Western Oil & Gas Association
Edward Wilson, Coordinator OCS Activities, Virginia

Summaries of the comments received, discussions for accepting or rejecting the suggestions of the commenters, and the final versions of the Orders are published below. The requirements of certain paragraphs and subparagraphs are different for the various Areas due to environmental, geological, geophysical, or geographical differences. The Areas which are affected by these varying requirements are identified in the appropriate paragraphs and subparagraphs of the Orders. Booklet copies of the final Orders for each Area will contain only those requirements which are applicable to that Area.

The term OCS Area as used herein is defined as an established organizational unit of a U.S. Geological Survey Region which is under the jurisdiction of an Area Oil and Gas Supervisor. An Area is comprised of one or more Districts which are under the administration of a District Supervisor.

These Area OCS Orders are applicable to leases on the Outer Continental Shelf. The term "Outer Continental Shelf" means all submerged lands lying seaward and outside of the area of lands beneath navigable waters as defined in section 2 of the Submerged Lands Act (Public Law 31, 83rd Congress, 1st Session) and of which the subsoil and seabed appertain to the United States and are subject to its jurisdiction and control.

Where these Area OCS Orders refer to approvals or determinations by the Supervisor, these references mean the appropriate Area Oil and Gas Supervisor. In those instances where approvals or determinations are to be made by the District Supervisor, the Orders so state and the determination is made by the appropriate District Supervisor.

Departures granted under the provisions of the previous Area OCS Orders shall remain in effect, provided those specific provisions under which the departures were granted remain unrevised in these Orders.

For further information, contact Mr. Richard B. Krahl, Chief of the Branch of Marine Oil and Gas Operations, Conservation Division, U.S. Geological Survey, Mail Stop 620, Reston, Virginia 22092 (703–860–7531). The primary author of this document is Mr. Lloyd M. Tracey, OCS Orders and Standards Section, Branch of Marine Oil and Gas Operations, Conservation Division, U.S. Geological Survey (703–860–7835).

Copies of the revised Area OCS Orders and copies of maps indicating the boundaries of jurisdictional Areas are available from the following:

Conservation Manager, Gulf of Mexico Region, U.S. Geological Survey, P.O. Box 7944, Metairie, Louisiana 70011.
Conservation Manager, Eastern Region, U.S. Geological Survey, 1725 K Street, N.W., Washington, D.C. 20244.

Conservation Manager, Western Region, U.S. Geological Survey, 345 Middlefield Road, Menlo Park, California 94025.
Area Oil and Gas Supervisor, Alaska Area, Skyline Building, Room 212, 800 A St., P.O. Box 259, Anchorage, Alaska 99501.
Area Oil and Gas Supervisor, Pacific Area, 7744 Federal Building, 300 N. Los Angeles St., Los Angeles, California 90012.
Chief, Conservation Division, U.S. Geological Survey, Mail Stop 620, National Center, 12201 Sunrise Valley Drive, Reston, Virginia 22092.

Copies of the U.S. Geological Survey Standards, which are referenced in Area OCS Order No. 2, are available from the Chief, Conservation Division, at the address above.

Dated: May 11, 1979.

J. R. Balsley,

Acting Director.

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OCS Order No. 1

Title and Preamble

Comments. No comments received.

Discussion. The title of OCS Order No. 1 was revised by adding the words "Mobile Drilling Units" to be consistent with the content of the Order.

The preamble was revised to state that the Order is "issued" rather than "established," pursuant to the authority prescribed in 30 CFR 250.11. The last sentence of the preamble pertaining to departures was deleted and inserted into the last paragraph of the Order, as this is a requirement that should appear in the text of the Order rather than in the preamble. These revisions of the preamble will be incorporated into all OCS Orders.

Paragraphs Nos. 1, 3, and 4.

Comments. One commenter expressed concern that paragraphs Nos. 1 and 3 did not address the lighting of fixed structures and suggested that the marking of submerged objects should include "all-weather" aides to navigation. Another commenter suggested that marker buoys would not remain in place; therefore, the Order should require the owner to notify the U.S. Coast Guard (USCG) and the fishing and shrimping associations of the location of the object.

The USCG suggested the Order should state that the requirements for the marking of submerged objects should be determined by the U.S. Coast Guard District Commander.

Discussion. OCS Order No. 1 does not address the lighting of all surface facilities because the lighting of artificial islands and mobile drilling vessels is governed by regulations of the USCG.

Since the determination of hazards to navigation or to commercial fishing operations is a function of the U.S. Coast Guard District Commander, we have adopted the suggestion of the USCG and have revised paragraph No. 4 as follows:

"4. *Identification of Subsea Objects.* All subsea objects resulting from lease operations which are determined by the U.S. Coast Guard District Commander to be hazards to navigation or to the deployment of commercial fishing devices shall be identified by suitable aid-to-navigation devices as directed by the District Commander. Prior to the establishment of a subsea object, or in the event of the accidental submergence of an object, the owner shall inform the District Commander of the object's description, location, and unobstructed depth of water above the object's highest point. Based on this information, the District Commander will determine what marking and permits, if any, will be required (14 USC 83, 85; 43 USC 1333; 33 CFR 67). The owner shall maintain these navigational markings onsite and properly functioning at all times while the obstruction remains."

Paragraph No. 2

Comments. One commenter suggested that paragraph No. 2, "Identification of Nonfixed Platforms or Structures," should be titled "Identification of Mobile Drilling Units" because the paragraph addressed semi-submersibles, jack-ups, and drill ships. This terminology would also be consistent with proposed OCS Order No. 2 and with the U.S. Coast Guard regulations.

Discussion. The title has been revised to reflect this change.

United States Department of the Interior; Geological Survey Conservation Division

OCS Order No. 1, Effective July 1, 1979; Identification of Wells, Platforms, Structures, Mobile Drilling Units, and Subsea Objects

This Order is issued pursuant to the authority prescribed in 30 CFR 250.11 and in accordance with 30 CFR 250.37.

1. *Identification of Fixed Platforms or Structures.* Platforms and structures shall be identified at two diagonal corners by a sign with letters and figures not less than 30 centimeters (12 inches) in height with the following information:

a. The name of the lease operator.

b. The area designation based on OCS Official Protraction Diagrams.

c. The block number in which the platform or structure is located.

d. The platform or structure designation.

The information shall be abbreviated as in the following example:

The Blank Oil Company operates "C" platform on Block 999 of the Salisbury Area. The identifying sign on the platform would indicate: BOC–SAL–999–C.

2. *Identification of Mobile Drilling Units.* Floating semisubmersible platforms, bottom-setting mobile rigs, and drilling ships shall be identified by one sign with letters and figures not less than 30 centimeters (12 inches) in height affixed to the derrick so as to be visible to approaching traffic and containing the following information:

a. The name of the lease operator.

b. The area designation based on OCS Official Protraction Diagrams.

c. The block number in which the drilling unit is located.

d. The OCS lease number.

e. The well number.

3. *Identification of Wells.* The OCS lease and well numbers shall be painted on, or a sign affixed to, the wellhead of each singly completed well. In multiply completed wells, each completion shall be individually identified at the wellhead. All identifying signs shall be maintained in a legible condition.

4. *Identification of Subsea Objects.* All subsea objects resulting from lease operations which are determined by the U.S. Coast Guard District Commander to be hazards to navigation or to the deployment of commercial fishing devices shall be identified by suitable aid-to-navigation devices as directed by the District Commander. Prior to the establishment of a subsea object or in the event of the accidental submergence of an object, the owner shall inform the District Commander of the object's description, location, and unobstructed depth of water above the object's highest point. Based on this information, the District Commander will determine what marking and permits, if any, will be required (14 USC 83, 85; 43 USC 1333; 33 CFR 67). The owner shall maintain these navigational markings onsite and properly functioning at all times while the obstruction remains.

5. *Departures.* All departures from the requirements specified in this Order shall be subject to approval, pursuant to 30 CFR 250.12(b).

Approved:
Don E. Kash,
Chief, Conservation Division.

OCS Order No. 2

General Comments

Comments. No comments received.

Discussion. Due to technical and editorial revisions, the paragraph numbering has been changed in this Order. In the discussions of the revisions, the new paragraph numbering coincides with the final Order. The former paragraph numbering is shown in parentheses.

Comments. One commenter stated that "Onshore impacts from OCS Sales will be felt by the coastal communities prior to the adoption of the various state Coastal Zone Management plans." It was recommended that "A special lease stipulation should be promulgated to require OCS lessees to certify that their exploration and development plans are consistent with adopted Regional Master Plans as well as State Coastal Zone Management plans."

Discussion. Since the publishing of the proposed National OCS Orders in the **Federal Register**, revised 30 CFR 250.34 was published in the **Federal Register**, Vol. 43, No. 19, on January 27, 1978. A proposed revision to this regulation, conforming to the recently enacted 1978 amendments to the OCS Lands Act (PL95–372), was also published in the **Federal Register**, Vol. 44, No. 12, January 17, 1979. Since both of these publications require the submittal of documents certifying that exploration and development plans are consistent with approved State Coastal Zone Management programs, it is not believed that a special lease stipulation will be necessary.

Comments. One commenter stated that "The proposed order, in its entirety, appears to ignore existing API documents which outline adequate industry procedure."

Discussion. The United States Geological Survey (USGS) disagrees with this statement. Appropriate recommended practices and specifications published by the American Petroleum Institute (API) are referenced throughout the OCS Orders as well as standards established by other organizations and the USGS.

Preamble

Comments. One commenter addressed the second sentence of the first paragraph of the Preamble, stating that the phrase "* * * in effect until field rules are issued" should definitely be kept in this Order.

Discussion. The statement has been retained in the Order; however, the requirements for the establishment of field drilling rules are now incorporated into a new paragraph 10, "Field Drilling Rules." The intent of the preamble is to cite the authority for the issuance of the Orders, rather than to state specific requirements. Other requirements, pertaining to plans and applications, which were in the preamble were incorporated into the body of the Order for the same reason.

Paragraph 1

Comments. No comments received.

Discussion. The requirements for the submittal of plans and the Application for Permit to Drill, which were formerly addressed in the preamble, were incorporated into a new paragraph 1, "Plans and Applications," for the reason given in the preceding discussion. All subsequent paragraphs were renumbered.

Subparagraph 1.2

Comments. No comments received.

Discussion. The following sentence was added: "Additionally, the Supervisor will prescribe the number of public information copies to be submitted." The additional copies are required for submittal to States requesting copies in accordance with 30 CFR 250.34.

Subparagraph 2.1.1

Comments. It was suggested that the second sentence in subparagraph 2.1.1 (1.1.1) be changed to "The operator or drilling contractor shall * * *."

Discussion. This suggestion was not accepted because the lessee is legally responsible for drilling and developing the lease. The drilling contractor is considered the lessee's agent. Therefore, the word "operator" was replaced by the word "lessee." This revision was incorporated wherever the word "operator" appeared in all of the Orders.

Comments. One commenter suggested that the second sentence of 2.1.1 (1.1.1) was redundant and should be deleted because the requirements of the proposed subparagraphs 1.1.2, 1.1.4 and 1.2(a) and (b) addressed the same subject.

Discussion. The intent of this sentence was to state the requirement for the lessee to furnish evidence of the fitness of the drilling unit to perform the planned operations. The proposed subparagraph 1.1.4 recited the information which is required to evaluate the fitness of the drilling unit. The language of the subparagraph was revised to require the "rated capacity of all major drilling equipment * * *." This language was then incorporated into subparagraph 2.1.1 instead of a separate subparagraph (1.1.4). Refer to the comments and discussion of subparagraph 2.1.4 (1.1.4).

Comments. It was recommended that "* * * insertion of the intent of the Memorandum of Understanding (MOU) dated April 11, 1977, between the United States Coast Guard (USCG) and the USGS into this section will minimize duplication of regulatory efforts, reduce the burden on industry, and provide equal or more effective safety and pollution control."

Discussion. The third sentence of subparagraph 2.1.1 was revised to indicate the intent of the MOU. The subparagraph requires the submittal of information on equipment "associated with the drilling operation"; therefore, this requirement does not constitute a duplication of regulatory efforts. The USCG will inspect and approve the drilling equipment, its related systems, and the use of a mobile drilling unit at a particular location; whereas, the USGC will inspect and approve the systems relating to the safety and health of personnel, the general safety and integrity of the unit, and the marine and industrial systems as outlined in the MOU between the USCG and the USGS.

Comments. One commenter suggested that "Seismic (including tsunamis) conditions should be inserted along with oceanographic and meteorological considerations."

Discussion. Subparagraph 2.2b (1.2b) has been revised to require that application for drilling from mobile drilling units shall include "seismic motion to be encountered at the drill site during the period of drilling operations." Forces due to tsunamis would be included in this seismic motion data. Furthermore, subparagraph 2.3 (1.3) requires that applications for placement of fixed drilling platforms or structures shall be submitted in accordance with OCS Order No. 8, which in turn requires that the design of all artificial islands or structures shall consider forces due to seismic motion.

The following discussion is quoted from a report entitled "Environmental Design Data for the Gulf of Alaska (Update No. 3)," September 1977, which was prepared for the USGS by the Aerospace Corporation:

The damaging effects of tsunamis are primarily limited to very shallow water and coastal areas where the tsunami may be transformed to a breaking wave of great magnitude. In the open waters of the OCS lease, however, the tsunami is felt only as a rapid rise in sea level which imparts very little horizontal force to structures it may encounter. Since this phenomenon is frequently misunderstood, it is useful to place it in perspective by comparing the forces generated by both a large storm wave and a tsunami. According to Horrer (1975), a large tsunami which raised the water level 30 feet in 5 minutes at a site where the water depth is 200 feet would produce water particle horizontal accelerations and velocity maxima of 0.15 ft/sec ^{2} and 7 ft/sec., respectively. Similar water particle accelerations and velocities for a 90-foot-high storm wave with a 16-second period in the same water depth would be 8 ft/sec ^{2} and 20 ft/sec at the surface and 4 ft/sec ^{2} and 10 ft/sec at the bottom. Thus, from an offshore platform design standpoint, tsunamis can be treated in the same manner as a rise in water level elevation.

In view of the conclusions of the Aerospace Corporation's report, we believe that our requirement for the submission of seismic motion data and maximum-anticipated wave heights for both fixed and mobile platforms adequately covers the requirement for this data.

Comments. One commenter submitted a discussion of the merits and favorable aspects of using drill ships over other types of mobile drilling units in the Gulf of Alaska.

Discussion. The USGS considers the guidelines in new subparagraphs 2.1.1, "Fitness of Drilling Unit," and 2.1.2, "Pre-Drilling Inspection," sufficient and appropriate to determine the suitability of a mobile drilling unit to be approved for drilling in any OCS area, regardless of its configuration.

Subparagraph 2.1.2

Comments. It was suggested that the word "available" be added to the first sentence of subparagraph 2.1.2 (1.1.2) so that "a positive flow of events will occur with no unnecessary lost rig days."

Discussion. The suggestion was adopted for clarity.

Comments. It was suggested that the word "area" be clearly defined in subparagraphs 2.1.2 (1.1.2) and 2.2 (1.2).

Discussion. The word "area" has been defined in the preamble of this Notice. Copies of maps indicating the boundaries of these jurisdictional areas are available from the Conservation Managers at the addresses listed in the preamble of this Notice.

Subparagraph 2.1.3

Comments. It was recommended that the statement "* * * other surveys as required by the Supervisor * * *" be deleted from subparagraph 2.1.3 (1.1.3), and the wording changed to apply this section to exploratory wells only.

Discussion. The intent of the subparagraph was to recognize the Supervisor's authority to require archaeological or biological surveys. These surveys may be included in lease stipulations.

Comments. It was asked if well-site surveys "remain" with the District Supervisor. It was stated that the surveys should be forwarded to each involved State for review by appropriate personnel.

Discussion. Well-site survey data is maintained by the District Supervisor and may be reviewed by the public in accordance with subparagraph 2.10c of OCS Order No. 12 and the regulations set forth in 30 CFR 252.

Comments. It was suggested that "To be consistent with section 1.1.5, this section should mention that the requirements for well site surveys will be issued in an OCS Notice to Lessees."

Discussion. The subparagraph was not changed since survey requirements may vary within an OCS area. Survey requirements shall be considered on a case-by-case basis. A Notice to Lessees may not be the appropriate document to require these surveys.

Former Subparagraph 1.1.4

Comments. Several commenters addressed the original subparagraph 1.1.4 stating that in the first sentence, the term "performance data" should be changed to "rated capability." Furthermore, the word "major" should be inserted between the words "all" and "drilling." The reasons for these revisions concerned the necessity of submitting large volumes of data and drawings "* * * of *all* components of the rig's minor equipment."

Discussion. These comments have been adopted to clarify the intent of the subparagraph.

The original subparagraph 1.1.4 has been rewritten and is now included in subparagraph 2.1.1 beginning with the third sentence. Accordingly, original subparagraphs 1.1.4, 1.1.5, and 1.1.6 have been renumbered 2.1.3, 2.1.4, and 2.1.5, respectively.

Former Subparagraph 1.1.5

Comments. It was suggested that "* * * oceanographic and meteorological conditions be made available not just at any point in operation but in time to determine the fitness of the drilling units proposed for use."

Discussion. The U.S. Naval Oceanographic Office and the National Oceanographic and Atmospheric Administration (NOAA) have data that can be used by lessees to gain oceanographic and meteorological knowledge of most OCS areas. We agree that all available data should be used to determine the fitness of the drilling unit. It is the lessees' responsibility to gather this information and use it in formulating their programs for approval. Operational data will add to this data base.

Subparagraph 2.2

Comments. It was suggested that the USGS collaborate with the drilling contractor for criteria needed under subparagraph 2.2 (1.2), rather than with the operator.

Discussion. The USGS disagrees for the same reasons stated under subparagraph 2.1.1 on this subject.

Comments. It was suggested that subparagraph 2.2b (1.2b) be deleted because "* * * 'an average recurrence interval of 100 years' is extremely excessive * * *."

Discussion. The USGS agrees that the recurrence interval may vary as to the total length of time that a drilling unit may work in a given area. Accordingly, the subparagraph was rewritten to eliminate the 100-year recurrence interval. The revision requires that the information to be submitted shall be based on conditions "to be encountered at the drill site during the period of drilling operations."

Comments. It was noted that unless subparagraph 2.2c (1.2c) is deleted, "The USGS proposed requirement would require stacking of all domestic noncertified units until the U.S. Coast Guard certification program is implemented * * *."

Discussion. It is not the intent of the USGS to cause domestic noncertified rigs to be stacked in the Gulf of Mexico or in any other OCS Area. Until the USCG certification program is implemented, departures can be submitted in accordance with 30 CFR 250.12(b), as indicated in paragraph 11 of this Order. Departures would be granted for any Mobile Offshore Drilling Unit (MODU) which is waiting for the USCG to issue a Certificate of Inspection, provided the certificate is not being withheld due to failure to pass USCG inspection.

Comments. One comment was directed to subparagraph 2.2c stating that the USCG "'Certificate of Inspection' is the proper reference, rather than 'Certificate of Fitness' * * *."

Discussion. This Order was revised to correct the misnomer.

Comments. It was suggested that subparagraph 2.2c be restructured as follows: "Current American Bureau of Shipping Classification *and* U.S. Coast Guard Certificate of Inspection * * *."

Discussion. It is concluded that substituting the word "and" for the word "or" would render the statement somewhat redundant. In consultation with the USCG concerning the subject of inspection of mobile drilling vessels, they assure that *all* mobile offshore drilling units must meet all applicable USCG safety standards. Moreover, all foreign drilling vessels operating in any United States waters will be inspected by the USCG. Additionally, if a mobile drilling unit is moved from one OCS area to another OCS area, it will also be inspected by the USCG.

Comments. One commenter stated that "The bulk of the units drilling in the North Atlantic are not likely to be covered under these regulations."

Discussion. The phrase "or other appropriate classifications" was added to recognize that other foreign classifications might be acceptable as evidence of the fitness of the vessel.

Paragraph 3

Comments. No comments received.

Discussion. The requirements of paragraph 3 (2), "Well Casing and Cementing," were reorganized and segregated into the following subparagraphs:

3.1 "General Requirements"
3.2 "Drive or Structural Casing"
3.3 "Conductor and Surface Casing Setting and Cementing Requirements"
3.3.1 "Conductor and Surface Casing Setting Depths"
3.3.2 "Conductor Casing Cementing Requirements"
3.3.3 "Surface Casing Cementing Requirements"
3.4 "Intermediate Casing Setting and Cementing Requirements"
3.5 "Production Casing"
3.6 "Pressure-Testing of Casing"

These editorial revisions present the requirements in a logical sequence and provide an improved index of the requirements.

Subparagraph 3.1

Comments. A number of commenters addressed several aspects of paragraph 3 (2), "Well Casing and Cementing," subparagraph 3.1, "General Requirements." One commenter noted: "For the surface and intermediate casing strings the statement concerning improper cementing is unnecessary and leads to confused interpretation. The critical operation at this point is the pressure test below the surface & intermediate casing shoe, which is required. If this shoe test shows that the surface & intermediate casing, the cementing job, and the formation immediately below it are capable of supporting the maximum mud weight required to reach the next casing point, there would be no valid reason for repairing an "indicated improper" cement job. If the formation leaks off below the desired mud weight, squeeze cementing below the surface and intermediate casing shoe would be the desired course of action regardless of the other indications during the primary cementing operation. The current requirement is also objectionable from the standpoint that the phrase 'make the necessary repairs' could be construed to require squeezing through

perforations, which is probably the least desirable solution.

"The requirement for a temperature or cement bond log is not included in the current Gulf of Mexico Order 2 and we feel that it is inappropriate to include it in the National Order."

Discussion. The USGS is in general agreement with the foregoing comments; however, temperature surveys and cement bond logs are very useful tools in determining the top of cement in cases where there is a question as to the actual placement of the cement. The paragraph has been restructured to allow greater flexibility in conducting these operations. This allows a choice of the means to determine the adequacy of the cement job and the remedial action to be taken, based on an engineering evaluation.

Comments. One commenter stated: "We are aware that in some instances in the South Atlantic OCS, the primary limestone aquifer extends offshore and may be within 20 feet of the ocean floor. Should well abandonment in an area where the aquifer is within 20 feet of the ocean floor require washing out of cement to facilitate the abandonment process, there is a strong possibility that the aquifer would be unprotected from contamination or leakage. We recommend that appropriate provision be made in this Order for adequate protection of the aquifer during and after abandonment."

Discussion. It is intended that subparagraph 3.1 provide for protection of all freshwater zones, regardless of depth. If special provisions are required to protect very shallow freshwater zones on the OCS, the District Supervisor shall consider these aspects before approval of the lessee's Application for Permit to Drill.

Comments. Several commenters suggested that the phrase "design wellhead pressure" be inserted between "pressures" and "and" in the fourth line. It was contended that "The design wellhead pressure will take into account the expected well conditions such as mud density to be used, the exposed formation fracture pressure, the well and casing setting depths the mud weights used outside the casing being drilled through, and any other pertinent drilling factors." The rationale for this suggestion is quoted as follows: "The proposal of design wellhead pressure allows the designer of the well to base equipment selection on well conditions and permits the selection of equipment with higher safety factors and avoids penalizing operators that use higher pressure rating BOP's for convenience or heavier wall casing for wear allowance."

Discussion. The USGS does not agree. Lessees may evaluate all of the design aspects considered in this comment. However, one set of design factors for one lessee may be quite different from the design factors adopted by another lessee, and still another set of design factors established by a third lessee. Consequently, different wellhead (working/test pressure) assemblies may result.

We know of nothing restrictive or penalizing in the use of the phrase "maximum-anticipated surface pressure" instead of "design wellhead pressure." The lessee is free to use "higher safety factors" and to use "higher pressure rating BOPs." Refer to subparagraph 5.1.1. (4.1.1.), 5.2 (4.2), 5.3 (4.3), and 5.6 (4.6). There are no limits on the selection of the weights and grades of the casing strings. The lessee is free to select higher weights and grades for safety considerations and wear allowances. Finally, the term "maximum-anticipated surface pressure" allows for the theoretical possibility of a full column of reservoir gas pressure at the surface, with no liquids in the well, and in a drilling area of abnormally high pressure gradients.

Comments. It was suggested that the third paragraph under subparagraph 3.1 (2) be revised to include the following: "A request to waive this requirement shall be accompanied by sufficient supporting offset well experience and formation data to verify that the proposed well will not penetrate abnormally pressured intervals."

Discussion. This suggestion was not adopted. The lessee has the option to utilize appropriate drilling technology which the District Supervisor has approved for use.

Comments. One commenter stated: "All casing is required to be new pipe which meets API quality standards or reconditioned used pipe that has been tested to insure it will meet API quality standards. What is the basis for reliance on the API standard? What review of this standard has been made by USGS? What happens if the standard is modified after the Orders are adopted? Does the API standard represent the best available and safest technology (BAST)? None of the answers to these questions can be determined from the Order."

Discussion. Prior to referencing in an OCS Order, any specification, standard, or Recommended Practice published by the API, American Society of Mechanical Engineers (ASME), American National Standards Institute (ANSI), or any other organization, published standards on the subject are reviewed. The most appropriate standard which accomplishes the intended purpose is selected for referencing in the Order. These documents reflect the best available technology because they undergo continued review and updating on a periodic basis by committees responsible for maintaining the documents. This review system assures that the documents reflect current technology.

Generally, when a standard is referenced in an OCS Order, a specific edition is indicated, normally the most current edition. Before another or later revision of the standard would be accepted, a review of that edition would be conducted by personnel of the USGS to see that it continues to accomplish the intended purpose. The Chief, Conservation Division, will therefore approve the use of any modified standard. In this particular paragraph, the intention is to assure that all casing, whether new or used manufactured domestically or foreign, meet the minimum accepted standards for collapse, tension, internal yield pressure, and mill test data.

There are at least 10 API documents which apply to oil-well casing. Since the lessee may elect to cite several of these documents as requirements for the casing installation for a particular well condition, it is deemed sufficient to refer to applicable API Standards.

Subparagraph 3.2

Comments. The following comment was made on subparagraph 3.2 (2.1): "There are many areas where hard sea floor outcrops make 100' of 36" or 48" hole very impractical. The attempt to set a specific, minimum length of casing for *all* areas of OCS waters ignores and denies the intelligent use of shallow hazards survey data by both the District Supervisor and the operator."

Discussion. The USGS is aware of areas where hard seafloors exist, and agrees that in these areas some flexibility should be allowed. Accordingly, the first sentence of this subparagraph was changed to "* * * a minimum depth of 30 meters (98 feet) below the oceanfloor or to other depths, as may be required or approved by the District Supervisor * * *."

Subparagraph 3.3.2

Comments. One commenter addressed subparagraph 3.3.2 (2.2.1) and recommended the following addition to the end of the first sentence: "except that in floating drilling operations this casing shall be cemented with a minimum quantity of cement sufficient to fill the calculated annular space to a point within 30 meters (98 feet) of the bottom of the drive or structural casing.

"The proposed revision for floating drilling operations would provide flexibility to the operator to use lesser amounts of cement which would greatly facilitate casing salvage and subsequent abandonment operations, if conducted, and would virtually eliminate the possibility of fouling the template with cement returns to the Gulf floor. No added safety margin is gained by cementing the conductor-structural string annulus back to the Gulf floor since the formation immediately below the shoe of the structural string is relatively incompetent."

Discussion. This suggestion was not adopted since provision has been made to wash out the top 12 meters (39 feet) below the ocean floor. The following provision is included in subparagraph 3.1: "In cases where cement has filled the annular space back to the ocean floor, upon approval by the District Supervisor, the cement may be washed out or displaced to a depth not exceeding 12 meters (39 feet) below the ocean floor to facilitate casing removal upon well abandonment."

Comments. It was proposed that the word "annular" be inserted between the words "calculated" and "space" in the first sentence of subparagraph 3.3.2. (2.2.1). It was contended that "* * * the word 'annular' properly defines 'space' in this sentence."

Discussion. The USGS agrees, and the suggestion was adopted.

Subparagraph 3.3.3

Comments. One commenter suggested that in subparagraph 3.3.3 (2.2.2) "* * * the term 'freshwater sands' be changed to read 'freshwater zones' so as to ensure protection of the limestone aquifer which may also occur in that shallow surface zone offshore."

Discussion. The USGS agrees, and has changed the phrase to "freshwater zones."

Comments. It was suggested that the following be added after the second sentence of subparagraph 3.3.3 (2.2.2): "For floating drilling operations that use a one stack blowout preventer system, a lesser volume of cement is permissible to prevent sealing the bottom of the annular space between the conductor casing and surface casing. Any annular space open to the drilled hole below must be sealed as required by Order 3 upon abandonment."

The rationale for this addition is quoted: "If the surface-conductor casing annulus is sealed at the bottom when using a one-stack subsea blowout preventer system, the subsea casing hanger pack-off sealing this annulus cannot be effectively presssure tested without danger of collapse of the surface casing or the bursting of the conductor casing each time the BOP's are tested to pressures exceeding the collapse pressure of the casing. With some formation exposed below the conductor pipe, the formation should break down before collapse of the surface pipe or burst of the conductor pipe, if a leak occurs in the sealing arrangement."

Discussion. This suggestion was not adopted. For the purposes of this discussion, case "A" will represent the condition wherein surface casing has been set and cement is extended into the surface/conductor annulus. Case "B" is the condition whereby the surface is set and the top of cement is below the conductor shoe (which could expose porous and permeable zones). The USGS believes that case "A" is the better surface-casing setting and cementing procedure than case "B." Surface casing is intended to protect all freshwater zones and to provide an anchor for the BOP stack.

If a wellhead seal leak should develop which would allow pressure communication in the surface/conductor annulus, then no pressure testing of the BOPs would be possible under case "B" until the seal is repaired. Otherwise, a porous formation could take fluid indefinitely.

If the lessee is concerned that a BOP pressure testing under case "A" could cause collapse of the surface casing or burst of the conductor casing, then pressure should be monitored on the conductor/surface annulus during the pressure test. If a leak is indicated, the lessee should take remedial action.

Subparagraph 3.4

Comments. One commenter was concerned with the requirement of drilling 100' of new hole below the casing shoe as stated in subparagraph 3.4 (2.3). It was contended that "The stipulation allowing an operator to drill nearly 100' of new hole below a casing shoe is not prudent in all OCS areas. It would be sound operating practice to limit this to 49' or 15 meters."

Discussion. It is acknowledged that long cement plugs in "soft" formations can cause inadvertent hole-deviation problems. Accordingly, the subparagraph was changed to adopt this suggestion.

Comments. Another commenter concerned with the wording of subparagraph 3.4 (2.3) suggested: "Add the following after the second sentence of the second paragraph: 'This isolation requirement may be satisfied by squeezing prior to completion or abandonment.' "

Discussion. This recommendation was included in the subparagraph.

Comments. One commenter stated that subparagraph 3.4 (2.3) was unclear. It was contended that the "Order is unclear." We assume the wording on pressure testing below the casing shoe was intended to be consistent with Section 2.2.2. Our recommendation on Section 2.2.2 also applies to this section." It was stated in a comment on subparagraph 3.3.3 (2.2.2) that "We do not think it necessary or advantageous to determine fracture gradients on *all* OCS wells, particularly all wells after the first on multiwell platforms." The commenter also stated: "In addition determination of the fracture gradient requires that the formation immediately below the casing shoe be pumped into * * *."

Discussion. It was intended that subparagraphs 3.3.3. (2.2.2) and 3.4 (2.3) be consistent. Both subparagraphs were revised as follows: "After drilling a maximum of 15 meters (49 feet) of new formation, a pressure test shall be conducted to obtain data to be used in estimating the formation fracture gradient. Pressure data shall be obtained either by testing to formation leak-off or by testing to a predetermined equivalent mud weight."

Pressure tests below the casing shoes (surface and intermediate) are intended to "aid" the lessee in his estimation of formation fracture gradients and maximum mud weights to carry into intermediate and production holes. The Order does not require fracturing of the formation. The pressures from the tests are used to estimate the true fracture gradient and pore pressure.

When field drilling rules are established, allowance will be made for the pressure-testing requirements for the determination of formation fracture gradients on multiwell platforms.

Comments. One commenter expressed concern regarding the "wide range of casing setting depths" which are permitted. "It is recommended that the Pacific Area requirements for the conductor and surface casing setting depths be adopted for the other areas with the provision to set an intermediate casing string at 4500' or shallower, if required by leak-off tests performed after drilling out of the surface casing. This would provide for the desired safety in the shallow and intermediate drilling and yet permit deeper drilling which may be the case in these other areas."

Discussion. The USGS does not agree that intermediate casing should 'set "at 4500' or shallower" for all areas, or even throughout a given area. Due to geological, geophisical, and other reasons, this amount of surface pipe may be required in an area. For the same reasons, intermediate casing may not be required at several thousand feet below this depth. Moreover, to adopt a fixed depth for all areas is not feasible and can cause a lessee to set multiple intermediate strings which would not be required for the safe drilling and may prevent the completion of a well due to insufficient well-bore diameter.

Subparagraph 3.5

Comments. Several commenters objected to subparagraph 3.5 (2.4), "Production Casing," stating that" * * * paragraph 2.4 is so written that an open-hole gravel pack completion would not be allowed. Although this type completion procedure is not in common usage offshore, we see no reason why it should not be permitted."

Discussion. It was not the intent of this subparagraph to preclude open-hole completions. This subparagraph was amended to state that hole and slotted-liner completions are permitted when approved by the District Supervisor.

Comments. It was suggested that the second sentence in this subparagraph be revised to: " * * * annular fillup to a minimum of 150 meters (492 feet) above the uppermost hydrocarbon bearing zone."

Discussion. The meaning of the sentence is not changed by the addition or deletion of the word "bearing."

Subparagraph 3.6

Comments. The third sentence of subparagraph 3.6 (2.5) was objected to. It was recommended that the following be added: "except in floating drilling operations."

Discussion. It is agreed that testing the casing with mud instead of with water would simplify the testing operation. Accordingly, the sentence was deleted.

Comments. It was suggested that the third sentence in this subparagraph be deleted to eliminate testing the casing string with water. An unsafe situation could be created by displacing the mud in the top 30 meters (98 ft) with water, due to the reduction of the hydrostatic head of the fluid column.

Discussion. The USGS agrees with this suggestion, and the sentence was deleted.

Comments. It was suggested that the second and third paragraphs of this subparagraph be revised as follows: "After cementing any of the above strings, drilling shall not be commenced until a time lapse of 8 hours under pressure for conductor casing string or 12 hours under pressure for all other strings, or until the cement has reached a 500 psi compressive strength, whichever is earliest. Cement is considered under pressure if one or more float valves are employed and are shown to be holding the cement in place or when other means of holding pressure is used. All casing pressure tests shall be recorded on the driller's log. The typical performance data for the particular cement mix used in the well shall be used to determine the time lapse required."

Discussion. The phrase "* * * or until the cement has reached a 500 psi compressive strength, whichever is earliest" was not adopted because of the uncertainty of determining the true compressive strength under actual well conditions.

Comments. One commenter stated that "It is not prudent operating practice to stress tubular goods in a drilling mode to the new tubular, internal yield. This requirement, coupled with the .22 psi/ft test on production or intermediate casing set at 12,000' or deeper

with high mud weights will operate excessive test pressures.

"The gel cement used on some strings of drilled-in structural casing takes in excess of 8 hours to attain 500 psi compressive. For the case of soft sea bed sediments, the cement, when it finally attained 500 psi compressive strength would be several times stronger than sediments. This would make the WOC time a useless waste of rig time. The concept is sound for all other casing strings and should be rigorously applied. However, the structural casing should not be included in this requirement."

Discussion. It is not intended that tubular goods be overstressed, regardless of their age and usage. A requriement has been added to limit pressure testing of casing to 70 percent of the minimum internal-yield pressure. When testing casing set at any depth, allowance shall be made for mud weights, the 0.22 psi/ft factor, and for other considerations. As stated in subparagraph 3.6 (2.5), structural casing is not included in this requirement.

Comments. No comments received.

Discussion. A new paragraph has been added following the table in subparagraph 3.6 to require certain tests to verify the integrity of the surface casing after unscheduled side-tracking operations or fishing operations.

Comments. It was suggested that the third sentence of this subparagraph be changed to "* * * 3 percent in 10 minutes * * *" to reduce rig time.

Discussion. This suggestion was not adopted because a 3 percent pressure increment would be too small to read on a high pressure gage and 10 minutes is not considered sufficient time for temperatures to stabilize in the well. Furthermore, this leak-detection criteria has been successfully used in the Gulf of Mexico OCS Area since August 28, 1969.

Paragraph 4

Comments. Several commenters were concerned with the allowable deviation angles in paragraph 4 (3), "Directional Surveys," and suggested that "an average of" be added between the words "exceed" and "three" in the first sentence, and the same notation for the first sentence of the second paragraph. The principal reason for this suggestion is that the proposed maximum of 3 degrees is too restrictive for vertical holes.

Discussion. The USGS agrees with the suggestions and has adopted the phrase, "Wells are considered vertical if inclination does not exceed an average of 3 degrees from the vertical or the maximum individual inclination survey does not exceed 6 degrees."

Comments. Several commenters recommended that directional surveys should be taken at each 300 meters (984 ft) instead of the required 150 meter (498 ft) intervals in vertical wells. Conversely, one commenter recommended that "* * * the minimum intervals be reduced to at least 60 meters to be more consistent with industry practices."

Discussion. The USGS disagrees that directional surveys should be conducted at each 300 meter (984 ft) interval in frontier areas where rank wildcats are to be drilled. Numerous factors which cause the bit to deviate from the vertical include (but are not limited to):

1. Bit configuration.
2. Nature and relative position of the formations being drilled.
3. Presence of faults, etc.

In some OCS areas, there has been *no exploratory drilling experience.* Hence, it is not known what hole-deviation characteristics will be experienced. When sufficient drilling experience has been gained in these frontier OCS areas, new survey intervals will be considered and the requirement changed, if justified.

Experience in the Gulf of Mexico OCS Area has confirmed that a survey interval of 300 meters (984 ft) is satisfactory for vertical wells; therefore, this requirement will remain unchanged for the Gulf of Mexico OCS Area.

Subparagraph 5.1.1

Comments. It was noted that on subsea blowout-preventer stacks "annular preventers are not currently available for working pressures greater than 5,000 psi in 16¾-inch and larger sizes."

Discussion. The USGS appreciates this correction. The subparagraph was revised accordingly.

Subparagraph 5.1.1a

Comments. It was suggested that "6,300 kPa (1,204 psi)" be replaced with 1,400 kPa (203 psi) in subparagraph 5.1.1a (4.1.1a) to be consistent with API RP 53.

Discussion. The USGS acknowledges this error and the suggested values have been included in the subparagraph.

Comments It was suggested that the first sentence in this subparagraph be reworded to eliminate the "vague and undefined term, 50 percent operating fluid reserve" and adopt "1.5 times the volume to close all BOP equipment units * * *."

Discussion. The USGS agrees that the suggested term more clearly defines the requirement, and the suggestion has been adopted.

Comments. It was recommended that the second sentence in this subparagraph be reworded for clarification as follows: "An accumulator backup system supplied by a secondary power source independent of the primary power source * * *."

Discussion. The USGS concurs and acknowledges that there is no need for two complete accumulator systems.

Subparagraph 5.1.1d

Comments. It was suggested that subparagraph 5.1.1d (4.1.1d) be reworded for clarity.

Discussion. The USGS agrees with this suggestion and has reworded this subparagraph as suggested.

Subparagrtaph 5.1.1f

Comments. It was observed that the fill-up line referred to in subparagraph 5.1.1f (4.1.1f) should be located above the top preventer to eliminate an unsafe practice of filling up below the preventers through a valve that must hold full working pressure.

Discussion. The USGS agrees with the suggestion and has adopted the comment. The USGS admits that on subsea BOP stacks, no valve or outlet should be below the BOP stack. If the valve should get knocked off, the entire BOP system is lost.

Subparagraph 5.1.1h

Comments. It was recommended that a new subparagraph 5.1.1h (4.1.1h) be added to state that "The wellhead assembly shall have a working pressure at least equal to the designed wellhead pressure."

Discussion. The USGS accepts this suggestion. However, the term "maximum-anticipated surface pressure" has been adopted. The reasons for this substitution have been stated earlier in the discussions for OCS Order No. 2.

Subparagraph 5.1.2c

Comments. It was stated that subparagraph 5.1.2c (4.1.2c) "* * * should be deleted since we believe it unnecessary and it would be impractical to carry a safety valve for every size of casing to be run."

Discussion. The USGS disagrees with this suggestion. A swage and a valve can be used to satisfy this requirement.

Subparagraph 5.1.3

Comments. One commenter noted that ethylene glycol is mixed with a BOP control fluid additive to form solutions as strong as 43 percent, to prevent freezing. It was also stated that "ethylene glycol appears to be toxic to aquatic organisms." Therefore, it would be desirable to use a less toxic substance in the BOP system, or to consider other alternatives such as devising a method of recovering the fluids after the BOP stack has been tested.

Discussion. This comment would not apply to surface-blowout preventer stacks since the hydraulic-control unit is a closed system and no fluid is lost when the preventers are actuated. In the case of subsea-blowout preventer stacks, water-based hydraulic fluids are available. Work is in progress to reduce the toxicity of hydraulic fluids to minimum levels and to provide adequate antifreeze protection under all operational environments. When nontoxic antifreeze compounds are developed, their use will be required. It is recognized that small volumes of hydraulic fluid may be discharged; therefore, the USGS is receptive to other alternatives.

Subparagraph 5.2

Comments. Several organizations commenting on subparagraph 5.2 (4.2), "Subsea BOP Requirements," suggested that the annular or packoff head on top of the marine riser be deleted from the drive-pipe drilling operation. The marine riser should also be deleted. It was pointed out that "The use of a marine riser and a preventer on drive pipe is an inherently unsafe operating practice. There are very few areas where the shallow seafloor sediments below structural casing will support weighted drilling fluids in excess of seatwater. In the case of a gas flow, there would be an immediate loss of head when the riser unloaded. Without the riser, the sea would hold a constant back pressure on the formation. Without a riser, the rig can be moved off the hole with no structural

damage to the casing or base-plate assembly. The soft-bottom sediments exposed below the structured casing would not be broached in this case.

"The use of a riser will require excessive drilling times for the conductor pipe since this entire section would have to be underreamed."

Discussion. We agree that the use of a riser, when drilling below drive or structural pipe, is dependent upon the competency of the seafloor sediments below these strings. In those areas where a riser is used, however, we believe that a diverter system is required. We also agree that it would be imprudent to attempt to contain pressure below drive or structural pipe by the use of a pressure rotating packoff head. Therefore, the Order was revised by deleting the requirement for an annular or pressure rotating packoff-head-type preventer and by adding the following note:

"Note: 1. When drilling fluids are circulated to the drilling vessel, a diverter system as described in subparagraph 5.4.1 shall be installed on top of the marine riser."

Comments. It was suggested that the requirement for two 15 cm (6 inch) internal diameter diverter lines and full opening valves "would result in the obsolescence of equipment that is and has satisfactorily performed floating drilling well control in the Gulf of Mexico."

Discussion. Note 4 for the Gulf of Mexico OCS Area has been revised to recognize that many drilling rigs in the Gulf of Mexico OCS Area have complied with the requirement for 10 cm (4 inch) diameter diversion lines in accordance with Gulf of Mexico OCS Order No. 2 which became effective January 1, 1965. The USGS also believes that 15 cm (6 inch) diameter lines provide greater protection; therefore, the note was revised to require that new installations or modifications of diverter systems made after the effective date of the Order would require the use of 15 cm (6 inch) diameter lines.

Comments. It was suggested that the word "additionally" be deleted in Note 5 (***) in subparagraph 5.2 (4.2) and Note 2 (**) in subparagraph 5.3 (4.3) since "* * * this could be interpreted to require an added ram-type BOP."

Discussion. Note 5 in subparagraph 5.2 (4.2) and Note 2 in subparagraph 5.3 (4.3) were revised to make it clear that the BOP stack must be equipped with rams to fit each size of pipe in a tapered drill string.

Comments. It was suggested that the second sentence in the second paragraph of subparagraph 5.2 (4.2) be revised to provide for a suitable alternate to the subsea accumulator system, and that the term "power fluid" be added to clarify the meaning of "connection." It was further contended that " 'Loss of connection', as now stated, is vague in that it could pertain to either a loss of a control fluid connection, a loss of a power fluid connection, or both."

Discussion. USGS has no objection to include "a suitable alternate approved by the District Supervisor." The sentence was also changed to include the phrase "power fluid connection."

Comments. it was suggested that the second and third sentences of the second paragraph should be deleted because the requirements for a subsea accumulator, "failsafe-design" and "failsafe-valving," "* * * would render obsolete equipment that has been and is currently being used satisfactorily * * *."

Discussion. The second sentence was revised to allow for an alternative to a subsea accumulator system. The third sentence was revised as follows: "The blowout-preventer system shall include dual pod control systems in accordance with API RP 53, First Edition, February 1976, reissued February 1978, subsection 5.B.13, or subsequent revisions which the Chief, Conservation Division, has approved for use."

Subparagraph 5.3

Comments. No comments received.

Discussion. Note 1 (*) of subparagraph 5.3 (4.3) was revised to be identical with Note 4 (**) of subparagraph 5.2 (4.2). Refer to the discussion for subparagraph 5.2 (4.2).

Subparagraph 5.4

Comments. The general comments on subparagraph 5.4 (4.4) indicated that the requirements for surface BOPs and subsurface BOPs were not clear.

Discussion. A review of the comments on this subparagraph indicated that the subparagraph on surface BOPs and the subparagraph on subsurface BOPs should be reorganized to clarify the intent. Therefore, the original subparagraph 4.4.1, "Surface BOPs," was reorganized and retitled 5.4.1, "Drilling Operations from Bottom-Supported Rigs." The original subparagraph 4.4.2, "Subsea BOP," was also reorganized and retitled 5.4.2, "Floating Drilling Operations." The details of the reorganization and revisions are discussed under separate headings for each subparagraph.

Subparagraph 5.4.1

Comments. It was recommended that the second sentence of subparagraph 5.4.1 (4.4.2) be revised as follows: "The diverter system shall be equipped with remote control valves in the main and diverter flow lines that can be operated from the control panel prior to shutting in the well."

It was stated that "A catastrophic situation could be caused by the inability of an automatic valve being able to reliably detect and select the downwind diversion. This system should be manually controlled for the safest operation."

Discussion. The USGS considered that this suggestion was an added point in the safety of operation, and the suggestion was adopted.

Subparagraph 5.4.2

Comments. It was suggested that subparagraph 5.4.2 (4.4.3), "Floating Drilling Operations," be revised to clarify that the conductor hole may be drilled with or without a riser/diverter system.

Discussion. The subparagraph was changed to clarify this point. This point was further clarified by the revision of Note 1 (*) of subparagraph 5.2 (4.2) which requires the use of a diverter when a riser is used. Refer to the discussion of subparagraph 5.2.

Comments. It was the consensus of opinion to delete the requirement for drilling a small diameter pilot hole to obtain shallow hazards data because of mechanical and deviation control problems.

It was also contended that "A one barrel kick in an 8¾" hole reduces the hydrostatic head much more than a one barrel kick in a 17½" hole." It was further contended that "* * * drilling a pilot hole will increase the risk if shallow hazards or hydrocarbons are encountered, rather than decrease them, since the hole will need to be reamed to full diameter and will be open longer in total time than if a full sized hole were drilled to begin with and surface casing promptly set."

Discussion. The USGS agrees with the comments and has deleted the small diameter pilot hole requirement.

Subparagraph 5.6

Comments. It was suggested that subparagraph 5.6 (4.6b) be changed by deleting the phrase "In addition to the above," and also by deleting the word "additionally" to clarify that "* * * additional preventer bodies are not needed on the BOP stack but that pipe rams of the proper size must be installed."

Discussion. During our review of the comments on this subparagraph, it became apparent that editorial revisions were required because some of the material in subparagraphs a, b, c, d, and f have been previously addressed under subparagraph 5.1, "General Requirements." The requirements of the proposed subparagraph 4.6a were incorporated into subparagraph 5.6 to elaborate on the minimum requirements as stated in tabular form in subparagraphs 5.2 and 5.3. The content of subparagraph 4.6b was incorporated into Note 5 of subparagraph 5.2 and Note 2 of subparagraph 5.3. The phrase "in addition to the above" and the word "additionally" were deleted. Refer to the discussion for the revisions of subparagraph 5.2 (4.2). The original subparagraphs 4.6 c, d, e, and f were deleted since these requirements are addressed in subparagraph 5.1, "General Requirements."

Subparagraph 5.7

Comments. It was suggested that subparagraph 5.7 (4.7) should be revised to segregate the testing requirements into separate subparagraphs addressing testing requirements for surface blowout-preventer stacks and testing requirements for subsea blowout-preventer stacks. This suggestion was adopted by changing the title of paragraph 5.7 (4.7) to "Testing of BOP Systems" and reorganizing the requirements into the following subparagraphs:

5.7.1 "BOP Testing Frequency"

5.7.2 "Pressure Testing Surface BOP Systems"

5.7.3 "Pressure Testing Subsea BOP Systems"

5.7.4 "Actuation of Surface BOP Systems"

5.7.5 "Actuation of Subsea BOP Systems"

The comments and discussion on each of these subparagraphs are addressed under separate headings.

Subparagraph 5.7.1

Comments. No comments received.

Discussion. As indicated in the discussion for subparagraph 5.7, the title of this subparagraph has been changed to "BOP Testing Frequency." The content of the original subparagraph 4.7.1, "BOP Controls," has been incorporated into subparagraph 5.1.1b.

The revised subparagraph states the testing frequency required for surface and subsea BOP stacks.

Subparagraph 5.7.2

Comments. It was suggested that the requirements for pressure testing of surface blowout-preventer stacks should be rewritten as follows: "Ram type blowout-preventers and related control equipment shall be tested to at least the design wellhead pressure, except that the annular-type preventers shall not be tested above 70% of their rated working pressure."

Discussion. This suggestion was partially adopted. The subparagraph was rewritten to require that surface blowout-preventer stacks be pressure tested to the maximum-anticipated surface pressure or at 70 percent of the minimum internal yield pressure of the casing, whichever is less. The annular-type BOP shall be tested at 70 percent of its rated working pressure or 70 percent of the minimum internal yield pressure of the casing, whichever is less. The rationale for the use of the phrase "maximum-anticipated surface pressure" instead of "design wellhead pressure" has been previously addressed in the discussion for subparagraph 3.1. The revised language makes it clear that the minimum internal yield pressure of the casing must be considered in determining the test pressure of the blowout-preventer stack. The subparagraph was also revised to require that the blind ram shall be tested as required for pipe rams before drilling out of each casing or liner shoe. This revision eliminates the necessity of setting a casing plug to allow the testing of the blind rams. A sentence was also added to make it clear that the smaller-sized pipe rams in a tapered string shall be tested when the smaller pipe is within the stack during a trip. This sentence makes it clear that it is not necessary to make a "special trip" to test the smaller pipe rams in a tapered drill string. The revision also adopts the suggestion that annular-type preventers should not be tested above 70 percent of their rated working pressure. This limitation is intended to reduce the wear of the annular blowout preventers.

Subparagraph 5.7.3

Comments. It was suggested that subparagraph 5.7.3 (4.7.2) be revised as follows: "Subsea BOPs and all related well-control equipment shall be stump tested at the surface with water to at least the design wellhead pressure, except that the annular-type BOP shall not be tested above 70 percent of its rated working pressure."

Discussion. This suggestion was adopted except that the phrase "maximum-anticipated surface pressure" was used in lieu of the phrase "design wellhead pressure." The rationale for the use of the phrase "maximum-anticipated surface pressure" has been addressed in the discussion of subparagraph 3.1.

Comments. It was suggested that the ocean floor pressure tests of subsea blowout-preventer stacks should be based on the same criteria as the pressure test for surface blowout preventers.

Discussion. This suggestion was adopted by incorporating the following language into the subparagraph: "After the installation of the BOP stack on the seafloor, the control equipment and pipe rams, conforming to the drill string within the stack, shall be tested as required under subparagraph 5.7.2. Before drilling out of each casing or liner shoe, the blind-shear rams shall be tested as required for blind rams under subparagraph 5.7.2."

Subparagraph 5.7.4

Comments. It was recommended in subparagraph 5.7.4 (4.7.3a) that daily operational tests of pipe rams on subsea blowout preventers be eliminated due to excessive wear on the ram rubbers.

Discussion. The USGS agrees that complete closure of the pipe rams is not necessary to verify proper functioning. We have also recognized that this is true for both surface blowout-preventer stacks and subsea blowout-preventer stacks. Subparagraph 5.7.4a was revised by adding the following sentence: "In order to prevent damage to the rams, complete closure of the rams on drill pipe is not required, provided proper operation is indicated." Subparagraph 5.7.5, "Actuation of Subsea BOP Systems," was revised to make this requirement applicable to subsea blowout-preventer systems.

Subparagraph 5.7.5

Comments. It was suggested that subparagraph 5.7.5 (4.7.3) should require that all hydraulic systems except those actuating the blind-shear rams should be actuated from each control station and each control system to test the proper functioning of each station and systems.

Discussion. This suggested requirement was incorporated into the revised subparagraph.

Subparagraph 5.8

Comments. Several commenters suggested that the last two sentences of subparagraph 5.8 (4.8) be deleted because "The presently required actuation and test procedures are the most reliable method of determining subsea equipment problems * * *."

Discussion. This subparagraph was changed by rewording the penultimate sentence to allow for unfavorable weather and sea conditions. The last sentence was left in the subparagraph since the use of television equipment is an acceptable method of subsea inspections.

Comments. It was suggested that the phrase "manufacturer's recommended procedures" be changed to "industry accepted standards such as API RP 53."

Discussion. The USGS disagrees with this suggestion. We know of no better source than the manufacturer's manuals concerning parts, lubrication, and operational procedures on blowout preventers. The API RP 53 is an excellent document and is endorsed by the USGS. This document also refers to the manufacturer. The maintenance procedures of subsection 7.A.12b recommends: "Using closing pressures recommended by the manufacturer." Moreover, API RP 53 contains no information on the maintenance of subsea installations.

Subparagraph 5.9

Comments. It was suggested that the fifth sentence of the proposed subparagraph 4.9 be deleted. It was contended that the nature of drilling operations precludes the precise scheduling of drills, especially when the remoteness of locations and communications are considered.

Discussion. It is agreed that the scheduling of drills would impose an unnecessary burden on the lessee. Furthermore, drills should not be scheduled in order to retain the element of surprise as a test of the state of readiness of the drilling crew and equipment. The sentence was deleted.

Comments. No comments received.

Discussion. The title of the subparagraph was changed to "Blowout-Preventer Drills" to accurately describe the contents. The paragraph was revised to require that blowout-preventer drills shall be conducted in accordance with the well-control drill requirements of the USGS Outer Continental Shelf Standard, "Training and Qualifications of Personnel in Well-Control Equipment and Techniques for Drilling on Offshore Locations," No. T 1 (GSS–OCS–T 1), First Edition, December 1977, and subsequent revisions thereto. The subsection of the standard entitled "Well-Control Drills" outlines the requirements in greater detail then the requirements of the original subparagraph.

Subparagraph 6.1

Comments. The overall comments on subparagraph 6.1 (5.1) indicated that the subparagraph should be reorganized to state the requirements in a more logical sequence.

Discussion. The subparagraph was reorganized by first stating the criteria which is to be used to determine when the hole is to be filled. This requirement was then followed by a sentence which requires that the number of stands of drill pipe and drill collars that may be pulled prior to filling the hole and the equivalent mud volume shall be calculated and posted. This requirements was then followed by the sentence which requires the use of a device for measuring the amount of mud required to fill the hole.

Comments. It was suggested that the second paragraph should be revised as follows: "When coming out of the hole with the drill pipe, the annulus shall be filled before the change in mud level decreases bottom-hole pressure 75 psi or every five stands of drill pipe, whichever gives a lower decrease in bottom-hole pressure (BHP)."

Discussion. This suggestion was adopted. This language is superior to the original reference point of "98 feet of head loss." The revised language improves the definition of the critical parameters of loss of bottom-hole pressure and the time interval required between checks.

Comments. It was suggested that the sentence which required the posting of the maximum pressure which may be applied under the blowout preventer should be revised to require the posting of the "maximum pressure to be contained under the blowout preventer."

Discussion. This suggestion was adopted. The revised language accurately describes the process of containing and controlling the back pressure by the use of the blowout preventer and choke manifold.

Comments. It was pointed out that the phrase "vacuum type gas separator" should be used instead of "degasser" because a "degasser" is a specific type of gas separator.

Discussion. The USGS agrees and has changed the sentence accordingly. The USGS does not intend to allow the use of rig-fabricated, atmospheric-type separators in OCS waters. A vacuum-type gas separator will more efficiently remove the gas from the mud than atmospheric-pressure separators.

Subparagraph 6.2d

Comments. In a comment on subparagraph 6.2d (5.2d), it was suggested that derrick floor indicators of hydrocarbon data not be required if a mud logging unit is in use, provided that the monitoring is on a continuous basis, and a means for immediate communication with the derrick floor is provided.

Discussion. The USGS agrees with the suggestion, and this subparagraph was changed to provide that "* * * with indicators located in the mud-logging compartment or on the derrick floor. If the indications are in the mud-logging compartment, there shall be a means of immediate communication with the rig floor, and the equipment shall be continually manned."

Subparagraph 6.3a

Comments. On subparagraph 6.3a (5.3a), many of the commenters objected to the use of the phrase "Twice the volume * * *." It was contended that in a large number of drilling conditions, the dry storage capacity of the drilling unit would be exceeded.

Discussion. Subparagraph 6.3a (5.3a) was changed to delete the "twice the volume" requirement in acknowledgment that there are numerous drilling conditions where mud quantities of this magnitude would exceed the capacity of many drill units. The subparagraph now requires that the minimum quantities of mud material shall be based on the volume required to replace the calculated capacity of the downhole and active surface systems. The second paragraph was revised as follows: "When the mud quantity required exceeds the storage capacity of the drilling facility, the lessee shall maintain maximum mud inventories and must receive approval from the District Supervisor of the lessee's plans to resupply mud inventories in the event of an emergency. The plan shall include an estimate of the time required for delivery of the mud supplies."

Subparagraph 7.3

Comments. On subparagraph 7.3 (6.3), several commenters recommended that 1 year be allowed for compliance with the USGS Training Standard No. T 1 (GSS–OCS–T 1).

Discussion. The subparagraph was revised to require compliance by December 1, 1979. A paragraph was also added to recognize that any driller, toolpusher, or operator's representative who received training in well-control between December 1, 1975, and December 1, 1979, will be credited as having met the training requirements of the Standard. These dates and the guidelines which were published in the Federal Register, Vol. 43, No. 39, February 27, 1978, and Vol. 43, No. 246, December 21, 1978, will be utilized in the determination of the acceptability of training.

Comments. One commenter stated that they "had not yet seen OCS T–1," and suggested that API RP T–3 treated the subject of training adequately. "However, if it is your intention to use OCS Standard T 1 we would strongly suggest that industry comment be sought and considered."

Discussion. Industry, all interested parties, and individuals were given two opportunities to submit written comments from two draft publications in the Federal Register as follows:

1. A Notice of intent to draft a training standard was first published in the Federal Register, Vol. 41, No. 105, May 28, 1976. Two draft standards were published as a basis for comments; one by the State of California, and the other was API RP T–3. Written comments were requested to be submitted by June 28, 1976.

2. The proposes USGS Training Standard was published in the Federal Register, Vol. 41, No. 212, November 2, 1976. In addition to the initial USGS draft form of the Training Standard, this publication included "Comments on the Publication, May 28, 1976, With Geological Survey Rationale." Comments were requested to be submitted by January 1, 1977.

Finally, the First Edition of the USGS Training Standard, GSS–OCS–T 1, dated December 1977, was published in the Federal Register, Vol. 42, No. 251, December 30, 1977.

Paragraph 8

Comments. No comments were received on paragraph 8 (7), "Hydrogen Sulfide." However, several comments were received on the contents of the proposed revision of the USGS Outer Continental Shelf Standard, "Safety Requirements for Drilling Operations in a Hydrogen Sulfide Environment," No. 1, (GSS–OCS–1), which was published in the Federal Register, Vol. 43, No. 128, July 3, 1978.

Discussion. This paragraph was revised to reference the Second Edition of GSS–OCS–1 which incorporates appropriate comments as a result of the Federal Register solicitation. The Second Edition clearly defines the requirements for areas which are known to contain H_2S, for areas where the presence of H_2S is unknown, and for areas known to be free of H_2S.

Paragraph 9

Comments. A commenter suggested that paragraph 9 (8) be deleted. The commenter stated: "However, if a special provision of this nature is to be required, the following wording would be a significant improvement from the standpoint of clarity and operator flexibility." The commenter then presented a revised introductory paragraph which suggested that the critical operations and curtailment plan should be applicable to the entire OCS Area covered by the Order, rather than the Area of individual leases. The commenter then listed three items which required that the plans should include guidelines which the operator would follow to assure coordination control and curtailment of drilling operation, identify the person in charge at the site, and include an outline for additional safety and antipollution measures.

Discussion. The USGS review of the comments received on this subparagraph, the original proposed paragraph, and the commenter's suggested modifications indicated that the requirements for the plans for mature areas need not be as detailed as those for frontier areas; therefore, separate paragraphs were written for the Gulf of Mexico Area and the other Areas of the OCS. The requirements of the Gulf of Mexico Area are different because numerous drilling operations over the years have caused the lessee to encounter problems, weigh risks, and develop solutions for critical operations. This experience has also allowed the lessee to formulate plans in advance of commonly anticipated situations and to find the need for and methods of curtailment of certain operations.

An example of foreknowledge can be witnessed almost every year during hurricane season when lessee expedite emergency evacuation operations which consist of securing facility and moving personnel. The language suggested by the commenter was revised and adopted for the Gulf of Mexico Area. A paragraph was added which required the lessee to review the plan at least annually, to notify the District Supervisor of the results of the review, and to recognize that any amendments or modifications of the plan are subject to the approval of the District Supervisor.

Since the requirements for the Gulf of Mexico Area would remain constant for many leases, the introductory paragraph requires a plan to be submitted for each District Area.

The introductory paragraph for the requirements for the other Areas of the OCS was revised to be consistent with the paragraph for the Gulf of Mexico Area, except that a Contingency Plan is to be submitted for each lease. This difference is required because in these Areas environmental conditions, water depths, and bottom stability may vary from lease to lease and affect the criticality of certain operations. A new paragraph was added to require the identification of the person in charge at the site.

United States Department of the Interior, Geological Survey, Conservation Division

OCS Order No. 2, Effective July 1, 1979; Drilling Operations

This Order is issued pursuant to the authority prescribed in 30 CFR 250.11. All exploratory and development wells drilled

for oil and gas shall be drilled in accordance with 30 CFR 250.34, 250.41, 250.91, and the provisions of this Order except for those provisions superseded by the issuance of field drilling rules.

1. *Plans and Applications*

1.1 *Exploration Plan and Development and Production Plan.* In accordance with 30 CFR 250.34, the lessee shall submit Exploration Plans and Development and Production Plans to the Supervisor for approval. All wells drilled under the provisions of this Order shall be included in the appropriate plan.

1.2 *Application for Permit to Drill.* Prior to commencing drilling under an approved Exploration Plan or a Development and Production Plan, the lessee shall file, in triplicate, an Application for Permit to Drill (Form 9–331 C) with the District Supervisor for approval. Additionally, the Supervisor will prescribe the number of public information copies to be submitted. If drilling activity does not commence within 6 months after the approval date, the Permit to Drill will expire.

2. *Drilling From Fixed Platforms and Mobile Drilling Units*

2.1 *General Requirements.*

2.1.1 *Fitness of Drilling Unit.* All fixed and mobile drilling units shall be capable of withstanding the oceanographic and meteorological conditions for the proposed area of operations. The lessee shall submit evidence to the District Supervisor of the fitness of the drilling unit to perform the planned drilling operation. This evidence shall include drawings and specifications of the following:

a. The rated capacity of all major drilling equipment.

b. Drilling safety systems.

c. Firefighting equipment.

d. Pollution-prevention equipment associated with the drilling operation.

e. A schematic diagram of the drilling unit.

2.1.2 *Pre-Drilling Inspection.* Prior to commencing operations in an OCS Area, all fixed drilling platforms and mobile drilling units shall be made available for a complete inspection by the District Supervisor.

2.1.3 *Well-Site Surveys.* Lessees shall conduct a shallow geologic hazards survey, and other surveys as required by the Supervisor. In areas where shallow hazards or hydrocarbons are unknown, shallow high-resolution geophysical data shall be obtained. The results of these surveys and an analysis of the geological hazards shall be furnished to the District Supervisor. All data obtained from the surveys and all geophysical data relating to shallow hazards shall be furnished upon request to the District Supervisor.

2.1.4 *Oceanographic, Meterological, Performance Data.* Operators shall collect and report oceanographic, meteorological, and performance data during the period of operations. The type of information collected, method of collection, and report requirements will be as specified by the Supervisor.

2.1.5 *Subfreezing Operations.* Operators shall furnish evidence that the drilling equipment, drilling safety systems, and other associated equipment and materials are suitable for operations in those Areas which are subject to subfreezing conditions.

2.2 *Mobile Drilling Units.* Applications for drilling from mobile drilling units shall include the following:

a. Maximum environmental design criteria, operational criteria, and a critical operations plan as described in paragraph 9 of this Order.

b. Environmental data, statistical data and calculations which indicate the maximum-anticipated wave, wind, current values, and forces due to ice, icing, storm surges, and seismic motion to be encountered at the drill site during the period of drilling operations.

c. Current American Bureau of Shipping Classification, U.S. Coast Guard Certificate of Inspection, or other appropriate classifications, with operational limitations. Unless required by the Supervisor, after a mobile drilling unit has been approved for use in an area, the information detailed in subparagraph 2.1.1 need not be resubmitted unless there are changes in equipment which affect the rated capability of the unit.

2.3 *Fixed Drilling Platforms.* Applications for installations of fixed drilling platforms or structures, including artificial islands, shall be submitted in accordance with OCS Order No. 8.

3. *Well Casing and Cementing*

3.1 *General Requirements.* All wells shall be cased and cemented in accordance with the requirements of 30 CFR 250.41(a)(1). The Application for Permit to Drill shall include the casing design safety factors for collapse, tension, and burst. Wells drilled in areas which are underlain by freshwater aquifers shall have casing programs which are designed to protect the freshwater zones. In cases where cement has filled the annular space back to the ocean floor, upon approval by the District Supervisor, the cement may be washed out or displaced to a depth not exceeding 12 meters (39 feet) below the ocean floor to facilitate casing removal upon well abandonment. For the purpose of this Order, the several casing strings in order of normal installation are drive or structural, conductor, surface, intermediate, and production casing. If there are indications of inadequate cementing (such as lost returns, cement channeling, or mechanical failure of equipment in the surface-, intermediate-, and production-casing strings), the lessee shall evaluate the adequacy of the cementing operations by pressure testing the casing shoe, running a cement bond log, running a temprature survey, or a combination thereof before continuing operations. If the evaluation indicates inadequate cementing, the lessee shall recement or take other actions in accordance with the instructions of the District Supervisor. The lessee shall verify the adequacy of the remedial cementing operations as required by the District Supervisor.

The design criteria for all wells shall consider all pertinent factors for well control, such as:

a. Formation fracture gradients.

b. Formation pressure.

c. Maximum-anticipated surface pressure.

d. Casing setting depths.

The lessee shall utilize appropriate drilling technology and state-of-the-art methods, such as drilling-rate evaluation, shale-density analysis, or other appropriate methods in order to enhance the evaluation of conditions of abnormal pressure and to minimize the potential for the well to flow or kick.

All casing, except drive pipe or structural casing, shall be new pipe which meets or exceeds American Petroleum Institute (API) standards, or reconditioned used pipe that has been tested to assure that it will meet or exceed API standards for new pipe. If casing which is not fabricated to API standards is used, the manufacturer's specifications shall be included on the Application for Permit to drill (Form 9–331 C).

3.2 *Drive or Structural Casing.* This casing shall be set by drilling, driving, or jetting to a minimum depth of 30 meters (98 feet) below the ocean floor or to other depths, as may be required or approved by the District supervisor, in order to support unconsolidated deposits and to provide hole stability for initial drilling operations. If this portion of the hole is drilled, the drilling fluid shall be of a type that is in compliance with the liquid disposal requirements of OCS Order No. 7, and a quantity of cement sufficient to fill the annular space back to the ocean floor shall be used.

3.3 *Conductor and Surface Casing Setting and Cementing Requirements.*

3.3.1 *Conductor and Surface Casing Setting Depths.*

Gulf of Mexico

Casing design and setting depths shall be based upon all engineering and geologic factors, including the presence or absence of hydrocarbons, other potential hazards, and water depths. These strings of casing shall be set at the depths specified, subject to approved variation to permit the casing to be set in a competent bed, or through formations determined desirable to be isolated from the well by pipe for safer drilling operations; however, the conductor casing shall be set immediately prior to drilling into formations known to contain oil or gas, or, if unknown, upon encountering such formations. These casing strings shall be run and cemented prior to drilling below the specified setting depths. The District Supervisor may prescribe the exact setting depths for those wells which may encounter abnormal pressure conditions. Conductor casing setting depths shall be between 152 meters (499 feet) and 305 meters (1,000 feet) TVD below the Gulf floor. Surface casing setting depths shall be between 457 meters (1,499 feet) and 1,372 meters (4,500 feet) TVD below the Gulf floor.

Engineering and geologic data which are used to substantiate the proposed setting depths of the conductor and surface casing (such as estimated fracture gradients, pore pressures, shallow hazards, etc.) shall be furnished with Application for Permit to Drill.

Pacific

Casing design and setting depths shall be based upon all engineering and geologic factors, including the presence or absence of

hydrocarbons, other potential hazards, and water depths. These strings of casing shall be set at the depths specified, subject to approved variation to permit the casing to be set in a competent bed, or through formations determined desirable to be isolated from the well by pipe for safer drilling operations; however, the conductor casing shall be set immediately prior to drilling into formations known to contain oil or gas, or, if unknown, upon encountering such formations. These casing strings shall be run and cemented prior to drilling below the specified setting depths. The District Supervisor may prescribe the exact setting depths for those wells which may encounter abnormal pressure conditions. Conductor casing setting depths shall be between 91 meters (298 feet) and 152 meters (499 feet) TVD below the ocean floor. Surface casing setting depths shall be between 305 meters (1,000 feet) and 366 meters (1,200 feet) TVD below the ocean floor, but may be set 457 meters (1,499 feet) in the event that conductor casing is set as deep as 137 meters (499 feet) TVD below the ocean floor.

Engineering and geologic data which are used to substantiate the proposed setting depths of the conductor and surface casings (such as estimated fracture gradients, pore pressures, shallow hazards, etc.) shall be furnished with the Application for Permit to Drill.

Gulf of Alaska and Atlantic

Casing design and setting depths shall be based upon all enineering and geologic factors, including the presence or absence of hydrocarbons, other potential hazards, and water depths. These strings of casing shall be set at the depths specified, subject to approved variation to permit the casing to be set in a competent bed, or through formations determined desirable to be isolated from the well by pipe for safer drilling operations; however, the conductor casing shall be set immediately prior to drilling into formations known to contain oil or gas, or, if unknown, upon encountering such formations. These casing strings shall be run and cemented prior to drilling below the specified setting depths. The District Supervisor may prescribe the exact setting depths for those wells which may encounter abnormal pressure conditions. Except as may otherwise be prescribed, conductor casing setting depths shall be between 91 meters (298 feet) and 305 meters (1,000 feet) TVD below ocean floor, and surface casing setting depths shall be between 305 meters (1,000 feet) and 1,400 meters (4,593 feet) TVD below ocean floor.

Engineering, geophysical, and geologic data used to substantiate the proposed setting depths of the conductor and surface casings (such as estimated fracture gradients, pore pressures, shallow hazards, etc.) shall be furnished with the Application for Permit to Drill.

3.3.2 *Conductor Casing Cementing Requirements.* Conductor casing shall be cemented with a quantity of cement sufficient to fill the calculated annular space back to the ocean floor. Cement fill to the ocean floor shall be verified by the observation of cement returns. In the event that observation of cement returns is not feasible or possible, an excess volume of cement shall be used to assure fill to the ocean foor. The excess volume shall be approved by the District Supervisor.

3.3.3 *Surface Casing Cementing Requirements.*

Gulf of Mexico, Gulf of Alaska, and Atlantic

Surface casing shall be cemented with a quantity of cement sufficient to protect all freshwater zones, to provide well control until the next string of casing is set, and with sufficient cement to fill the calculated annular space to at lest 60 meters (197 feet) inside the conductor casing.

After drilling a maximum of 15 meters (49 feet) of new hole, a pressure test shall be conducted to obtain data to be used in estimating the formation fracture gradient. Pressure data shall be obtained either by testing to formation leak-off or by testing to a predetermined equivalent mud weight.The results of this test and any subsequent tests of the formation shall be recorded on the driller's log and used to determine the depth and maximum mud weight to be used in the intermediate hole.

Pacific

Surface casing shall be cemented with a quantitiy of cement sufficient to protect all freshwater zones, to provide well control until the next string of casing is set, and with sufficient cement to fill the calculated annular space to the ocean floor, or as approved by the District Supervisor.

After drilling a maximum of 15 meters (49 feet) of new hole, a presure test shall be conducted to obtain data to be used in estimating the formation fracture gradient. Pressure data shall be obtained either by testing to formation leak-off or by testing to a predetermined equivalent mud weight. The results of this test and any subsequent tests of the formation shall be recorded on the driller's log and used to detemmine the depth and maximum mud weight to be used in the intermediate hole.

3.4 *Intermediate Casing Setting and Cementing Requirements.* One or more strings of intermediate casing shall be set when required by anticipated normal pressure, mud weight, sediment, and other well conditions. The setting depth for intermediate casing shall be based on the pressure tests of the exposed formation below the surface casing shoe or on subsequent pressure tests. After drilling a maximum of 15 meters (49 feet) of new hole, a pressure test shall be conducted to obtain data to be used in estimating the formation fracture gradient. Pressure data shall be obtained either by testing to formation leak-off or by testing to a predetermined equivalent mud weight. The results of this test and any subsequent tests of the formation shall be recorded on the driller's log and used to detemine the depth and maximum mud weight to be used in the hole below the intermediate-casing string.

A quantitiy of cement sufficient to cover and isolate all hydrocarbon zones and to isolate abnormal pressure intervals from abnormal pressure intervals shall be used. This requirement for isolation may be satisfied by squeeze cementing prior to completion, suspension of operations, or abandonment, whichever occurs first. Sufficient cement shall be used to provide annular fill-up to a minimum of 150 meters (492 feet) above the zones to be isolated or 150 meters (492 feet) above the casing shoe in cases where zonal coverage is not required.

If a liner is used as an intermediate string, it shall be lapped a minimum of 30 meters (98 feet) into the previous casing string and cemented as required for intermediate casing. The liner shall be tested by a fluid entry or pressure test to determine whether a seal between the liner top and the next larger string has been achieved. The test shall be recorded on the driller's log. If the test indicates an improper seal, the top of the liner shall be squeeze cemented. When such liner is used as production casing, it shall be extended to the surface and cemented to avoid surface casing being used as production casing.

3.5 *Production Casing.* Production casing shall be set before completing the well for production. It shall be cemented in a manner necessary to cover or isolate all zones above the shoe which contain hydrocarbons; but in any case, a calculated volume sufficient to fill the annular space at least 150 meters (492 feet) above the uppermost hydrocarbon zone must be used. Open-hole and slotted-liner completions are permitted when approved by the District Supervisor.

When a liner is used as production casing below intermediate casing, it shall be lapped a minimum of 30 meters (98 feet) into the previous casing string and cemented as required for the production casing. Testing of the seal between the liner top and the next larger string shall be conducted as in the case of intermediate liners and recorded on the driller's log. If the test indicates an improper seal, the top of the liner shall be squeeze cemented.

3.6 *Pressure-Testing of Casing.* Prior to drilling the plug after cementing, all casing strings, except the drive or structural casing, shall be pressure-tested as shown in the table below. The test pressure shall not exceed 70 percent of the internal yield pressure of the casing. If the pressure declines more than 10 percent in 30 minutes or if there is another indication of a leak, the casing shall be recemented, repaired, or an additional casing string run, and the casing tested again. The above procedures shall be repeated until a satisfactory test is obtained.

Casing	Minimum surface pressure
Conductor	1,400 kilopascals (kPa) (203 psi)
Surface	6,900 kPa (1,000 psi).*
Intermediate, Liner, and Production	10,400 kPa (1,508 psi) or 5 kPa/m (0.22 psi/ft.) whichever is greater.*

* Must not exceed 70 percent of the minimum internal yield pressure.

In the event of unscheduled drill pipe operations such as an unscheduled side-tracking operation or a fishing operation, the surface pipe shall be pressure tested, calipered, or otherwise evaluated, as approved by the District Supervisor.

After cementing any of the above strings, drilling shall not be resumed until a time lapse of 8 hours under pressure for the conductor casing string or 12 hours under pressure for all other strings. Cement is considered under pressure if one or more float valves are employed and are shown to be holding the cement in place or when other means of holding pressure is used. All casing pressure tests shall be recorded on the driller's log.

In addition to the time lapse stated above, sufficient time must elapse to allow the bottom 153 meters (502 feet) of annular cement fill, or total length of annular cement fill, if less, to attain a compressive strength of at least 3,448 kPa (500 psi) or as approved by the District Supervisor before drilling resumes.

The typical performance data for the particular cement mix used in the well shall be used to determine the time lapse required.

4. *Directional Surveys*

Gulf of Mexico

The requirements of this paragraph for the Gulf of Mexico Region are the same as the requirements for the Areas listed below. The only exception is that the survey interval of 150 meters (492 ft), specified in the first subparagraph of this paragraph, is changed to 300 meters (984 ft) for the Gulf of Mexico requirements.

Pacific, Gulf of Alaska, and Atlantic

Wells are considered vertical if inclination does not exceed an average of 3 degrees from the vertical or the maximum individual inclination survey does not exceed 6 degrees. Inclinational surveys shall be obtained on all vertical wells at intervals not exceeding 150 meters (492 feet) during the normal course of drilling.

Wells are considered directional if inclination exceeds an average of 3 degrees from the vertical or the maximum individual inclination survey exceeds 6 degrees. Directional surveys giving both inclination and azimuth shall be obtained on all directional wells at intervals not exceeding 150 meters (492 feet) during the normal course of drilling and at intervals not exceeding 30 meters (98 feet) in all planning angle-change portions of the hole.

On both vertical and directional wells, directional surveys giving both inclination and azimuth shall be obtained at intervals not exceeding 150 meters (492 feet) prior to, or upon, setting surface for intermediate casing, liners, and at total depth. Composite directional surveys shall be filed with the District Supervisor. The interval shown will be from the botton of conductor casing or, in the absence of conductor casing, from the botton of drive or structural casing to total depth. In calculating all surveys, a correction from true north to Universal Transverse Mercator Grid north or Lambert Grid north shall be made after making the magnetic-to-true-north correction.

5. *Blowout-Preventer (BOP) Equipment Requirements*

5.1 *General Requirements.* Blowout preventers and related well-control equipment shall be installed, used, maintained, and tested in a manner necessary to assure well control.

5.1.1 *BOP Equipment.* Blowout-preventer equipment shall consist of an annular preventer and the specified number of ram-type preventers. The pipe rams shall be of proper size to fit the drill pipe in use. The working pressure of any blowout preventer shall exceed the maximum-anticipated surface pressure to which it may be subjected, except that the working pressure of the annular preventer need not exceed 34,475 kPa (5,000 psi).

Information submitted with the Application for Permit to Drill shall include the maximum-anticipated surface pressure and the criteria used to determine this pressure. All blowout-preventer systems shall be equipped with:

a. A hydraulic actuating system that provides sufficient accumulator capacity to supply 1.5 times the volume necessary to close all BOP equipment units with a minimum pressure of 1,400 kPa (203 psi) above the precharge pressure. An accumulator backup system, supplied by a secondary power source independent from the primary power source, shall be provided with sufficient capacity to close all blowout preventers and hold them closed. Locking devices shall be provided on the ram-type preventers. The method of BOP actuation control such as hydraulic, acoustic, or other methods, shall be described and included in the Application for Permit to Drill.

b. At least one operable remote blowout-preventer-control station, in addition to the one on the drilling floor. This control station shall be in a readily accessible location away from the drilling floor.

c. A drilling spool with side outlets, if side outlets are not provided in the BOP body, to provide for separate kill and choke lines.

d. A kill line equipped with 2 kill-line valves is required. The master valve shall be located adjacent to the BOP. This valve shall not normally be used for opening or closing on flowing fluid. The second valve shall be located adjacent to the master valve. This valve shall be used as the control valve.

e. A fill-up line above the uppermost preventer.

f. A choke manifold equipped in accordance with "API Recommended Practice for Blowout-Prevention Equipment Systems," API RP 53, First Edition, February 1976, reissued February 1978, Sections 3A and 3B, or subsequent revisions which the Chief, Conservation Division, has approved for use.

g. Valves, pipes, and fittings upstream of, and including, the choke manifold shall have a pressure rating at least equal to the maximum-anticipated surface pressure.

h. A wellhead assembly with a working pressure at least equal to the maximum-anticipated surface pressure.

5.1.2 *Auxiliary Equipment.* The following auxiliary equipment shall be provided and maintained in operable condition at all times:

a. A kelly cock shall be installed below the swivel and an essentially full-opening valve of such design that it can be run through blowout preventers shall be installed at the bottom of the kelly. A wrench to fit each valve shall be stored in a conspicuous location readily accessible to the drilling crew.

b. An inside blowout preventer and an essentially full-opening drill string safety valve in the open position shall be maintained on the righ floor at all times while drilling operations are being conducted. These valves shall be maintained on the rig floor to fit all connections that are in the drill string.

c. A safety valve shall be available on the rig floor assembled with the proper connection to fit the casing string that is being run in the hole at the time.

5.1.3 *Subfreezing Operations.* The blowout preventers and related control equipment shall be suitable for operations in those Areas which are subject to subfreezing conditions.

5.2 *Subsea BOP Requirements.* The minimum requirements for drilling below the casing strings for subsea blowout-preventer stacks are tabulated below:

Drive or structural	None required.[1 2]
Conductor	1—Annular.
	1—Diverter System.[2 4]
Surface	1—Annular.
	2—Pipe Rams.
	1—Blind Shear Ram.
Intermediate	1—Annular.
	2—Pipe Rams.[5]
	1—Blind Shear Ram.

Note.—1. When drilling fluids are circulated to the drilling vessel, a diverter system as described in subparagraph 5.4.1 shall be installed on top of the marine riser.

2. If returns to the surface cannot be established, refer to subparagraph 5.4.2.

3. The choke and kill lines or equivalent vent lines, equipped with necessary connections and fittings, can be used for diversion, if approved by the Supervisor, or an annular preventer or pressure-rotating, packoff-type head, equipped with suitable diversion lines, shall be installed on top of the marine riser.

Gulf of Mexico

4. To be installed on top of the marine riser. Diverter systems installed prior to the effective date of this Order shall include a minimum of two 10-centimeter (4-inch) internal diameter lines and full-opening valves. Diverter systems installed or modified after the effective date of this Order shall include a minimum of two 15-centimeter (6-inch) internal diameter lines and full-opening valves.

Pacific, Gulf of Alaska, and Atlantic

4. To be installed on top of marine riser. The diverter system shall provide, as a minimum, two 15-centimeter (6-inch) internal diameter lines and full-opening valves.

All Areas

5. When a tapered drill string is in use, the BOP stack shall be equipped with pipe rams to fit both sizes of drill pipe.

Subsea blowout-preventer stacks shall be equipped with blind shear rams. A subsea accumulator or a suitable alternate approved by the District Supervisor is required to provide fast closure of the preventers and to operate all critical functions in case of loss of power fluid connection to the surface. The

blowout-preventer system shall include dual pod control systems in accordance with API RP 53, First Edition, February 1976, reissued February 1978, subsection 5.B.13, or subsequent revisions which the Chief, Conservation Division, has approved for use. Prior to the removal of the marine riser for installing casing, the riser shall be displaced with sea water. Sufficient hydrostatic head shall be maintained within the well bore to compensate for the reduction to head and to maintain a safe well condition. If repair or replacement of the blowout-preventer stack is necessary after installation, this work shall be accomplished after casing has been cemented prior to drilling out the casing shoe or by setting a cement or bridge plug to assure safe well conditions.

5.3 *Surface BOP Requirements.* The minimum requirements for drilling below the casing strings for conventional surface blowout-preventer stacks are tabulated below:

Drive or structural	1—Diverter System.[1]
Conductor	1—Annular. 1—Diverter System.[2,4]
Surface	1—Annular. 2—Pipe Rams. 1—Blind Ram.
Intermediate	1—Annular. 2—Pipe Rams.[3] 1—Blind Ram.

Gulf of Mexico

Note.—1. Diverter systems installed prior to the effective date of this Order shall include a minimum of two 10-centimeter (4-inch) internal diameter lines and full-opening valves. Diverter systems installed or modified after the effective date of this Order shall include a minimum of two 15-centimeter (6-inch) internal diameter lines and full-opening valves.

Pacific, Gulf of Alaska, and Atlantic

1. The diverter system shall include a minimum of two 15-centimeter (6-inch) internal diameter lines and full-opening valves.

All Areas

2. When a tapered drill string is in use, the BOP stack shall be equipped with pipe rams to fit both sizes of drill pipe.

5.4 *Drive Pipe or Structural Casing BOP Requirements.*

5.4.1 *Drilling Operations from Bottom-Supported Rigs.* Before drilling below this string with a bottom setting rig, a diverter system and related equipment shall be installed for circulating the drilling fluid to the drilling structure. The diverter system shall be equipped with remote control valves in the main and diverter flow lines that can be operated from the control panel prior to shutting in the well. The diverter lines shall vent in different directions to prevent downwind diversion. A schematic diagram and operational procedures for the diverter system shall be submitted with the Application for Permit to Drill (Form 9–331 C) to the Drill Supervisor for approval.

5.4.2 *Floating Drilling Operations.* In drilling operations where a floating or semi-submersible type of drilling vessel is used and formation competency at the structural casing setting depth is not adequate to permit circulation of drilling fluids to the vessel while drilling the conductor hole, a program which provides for safety in these operations shall be described and submitted to the District Supervisor for approval. This program shall include all known pertinent information, including seismic and geologic data, water depth, drilling-fluid hydrostatic pressure, a schematic diagram indicating the equipment to be installed from the rotary table to to proposed conductor-casing seat, and a contingency plan for moving off locations.

5.5 *Conductor Casing.* Before drilling below this string, at least one remote-controlled, annular-type blowout preventer shall be installed. A diverter system and other equipment for circulating the drilling fluid to the drilling structure or vessel shall be installed as described in subparagraph 5.4.1.

5.6 *Surface and Intermediate Casing.* Before drilling below these strings, the blowout-preventer system shall consist of at least four remote-controlled, hydraulically operated blowout preventers including at least two equipped with pipe rams, one with blind rams, and one anular type. Subsea blowout-preventer stacks used with floating drilling vessels shall include one set of blind shear rams.

5.7 *Testing of BOP Systems.* Prior to conducting high-pressure tests, all BOPs shall be tested to a low pressure of 1,400 to 2,000 kPa (203 to 290 psi).

5.7.1 *BOP Testing Frequency.* Surface and Subsea BOP stacks shall be tested as follows:

a. When installed.

b. Before drilling out after each string of casing has been set.

c. At least once each week, but not exceeding 7 days between tests, alternating between control stations. A period of more than 7 days between tests may be allowed where drilling problems prevent testing and remedial efforts are being made, provided BOP tests will be conducted as soon as possible. Testing shall be at staggered intervals to allow each drilling crew to operate the equipment.

d. Following repairs that require disconnecting a pressure seal in the assembly.

5.7.2 *Pressure Testing Surface BOP Systems.* Ram-type BOPs and related control equipment shall be tested at the maximum-anticipated surface pressure or at 70 percent of the minimum internal yield pressure of the casing, whichever is the lesser. The annular-type BOP shall be tested at 70 percent of its rated working pressure or 70 percent of the minimum internal yield pressure of the casing, whichever is the lesser. Before drilling out of each casing or liner shoe, the blind rams shall be tested as required for pipe rams. When a tapered drill string is in use, the smaller pipe rams shall be tested when the smaller pipe is within the stack during a trip.

5.7.3 *Pressure Testing Subsea BOP Systems.* Subsea BOPs and all related well-control equipment shall be stump tested at the surface with water to the maximum-anticipated surface pressure, except that the annular-type BOP shall not be tested above 70 percent of its rated working pressure. After the installation of the BOP stack on the sea floor, the control equipment and pipe rams, conforming to the drill string within the stack, shall be tested as required under subparagraph 5.7.2. Before drilling out of each casing or liner shoe, the blind shear rams shall be tested as required for blind rams under subparagraph 5.7.2.

5.7.4 *Actuation of Surface BOP Systems.* The following minimum-actuation frequencies are required:

a. Pipe Rams—Daily. In order to prevent damage to the rams, complete closure of the rams on drill pipe is not required, provided proper operation is indicated.

b. Blind Rams—Once each trip while the drill pipe is out of the hole. If multiple trips are made, only one action per day is required.

c. Annular-Type Preventer—Once each week in conjunction with the pressure test.

d. Control Stations—Once each trip while the drill pipe is out of the hole; however, not more than once each day, if multiple trips are made.

e. Choke manifold valves, kelly cocks, drill pipe safety valves—Weekly.

5.7.5 *Actuation of Subsea BOP Systems.* The actuation frequency requirements for subsea BOP systems shall be the same as those listed in subparagraph 5.7.4 for surface BOP systems, except item "b" pertaining to blind rams.

The blind shear rams shall be actuated once each trip from alternate control stations and control systems; however, not more than once each day, if multiple trips are made. During the weekly pressure tests, all hydraulic systems except those actuating the blind shear rams shall be actuated from each control station and control system.

5.8 *Inspection and Maintenance.* All BOP systems, marine risers, and associated equipment shall be inspected and maintained in accordance with the manufacturer's recommended procedures. The BOP systems and marine risers shall be visually inspected at least once each day if the weather and sea conditions permit the inspection. Inspection of subsea installations may be accomplished by the use of television equipment.

5.9 *Blowout-Preventer Drills.* All drilling personnel shall be indoctrinated in blowout-preventer drills and be familiar with the blowout-preventer equipment before starting work on the well. A blowout-preventer drill shall be conducted for each drilling crew in accordance with the well-control drill requirements of the U.S. Geological Survey Outer Continental Shelf Standard, "Training and Qualifications of Personnel in Well-Control Equipment and Techniques for Drilling on Offshore Locations," No. T 1 (GSS–OCS–T 1), First Edition, December 1977, and subsequent revisions thereto. A BOP drill may be required by a U.S. Geological Survey designated representative at any time during the drilling operation.

6. *Mud Program.* The characteristics, use, and testing of drilling mud and the implementation of related drilling procedures shall be designed to prevent the loss of well control. Sufficient quantities of mud materials shall be maintained readily accessible for use at all times to assure well control.

6.1 *Mud Control.* Before starting out of the hole with drill pipe, the mud shall be properly conditioned. Proper conditioning requires either circulation with the drill pipe just off bottom to the extent that the annular volume is displaced, or proper documentation in the driller's log prior to pulling the drill pipe as follows:

a. There was no indication of influx of formation fluids prior to starting to pull the drill pipe from the hole.

b. The weight of the returning mud is not less than the weight of the mud entering the hole.

c. Other mud properties recorded on the daily drilling log are within the specified ranges required by the mud program.

When the mud in the hole is circulated, the driller's log shall be so noted.

When coming out of the hole with drill pipe, the annulus shall be filled with mud before the change in mud level decreases the hydrostatic pressure 517 kPa (75 psi) or every 5 stands of drill pipe, whichever gives a lower decrease in hydrostatic pressure. The number of stands of drill pipe and drill collars that may be pulled prior to filling the hole and the equivalent mud volume shall be calculated and posted. A mechanical, volumetric, or electronic device for measuring the amount of mud required to fill the hole shall be utilized.

When there is an indication of swabbing or influx of formation fluids, the necessary safety devices and action shall be employed to control the well. The mud shall be circulated and conditioned, on or near bottom, unless well or mud conditions prevent running the drill pipe back to the bottom.

For each casing string, the maximum pressure to be contained under the blowout preventer, before controlling excess pressure by bleeding through the choke, shall be posted near the driller's control console.

An operable vacuum-type gas separator shall be installed in the mud system prior to commencement of drilling operations. The separator shall be maintained for use throughout the drilling and completion of the well.

The mud in the hole shall be circulated or reverse-circulated prior to pulling drill-stem test tools from the hole.

6.2 *Mud Testing and Monitoring Equipment.* Mud-testing equipment shall be maintained on the drilling rig at all times, and mud tests shall be performed once each tour, or more frequently, as conditions warrant. Such tests shall be conducted in accordance with procedures outlined in "API Recommended Practice for Standard Procedure for Testing Drilling Fluids," API RP 13B, Seventh Edition, April 1978, or subsequent revisions which the Chief, Conservation Division, has approved for use. The results of the tests shall be recorded and maintained at the drill site.

The following mud-system monitoring equipment shall be installed with derrick floor indicators and used when mud returns are established and throughout subsequent drilling operations:

a. Recording mud pit level indicator to determine mud pit volume gains and losses. This indicator shall include both a visual and an audio warning device.

b. Mud-volume measuring device for accurately determining mud volumes required to fill the hole on trips.

c. Mud-return indicator to determine that returns essentially equal the pump discharge rate.

d. Gas-detecting equipment to monitor the drilling mud returns, with indicators located in the mud logging compartment or on the derrick floor. If the indicators are in the mud-logging compartment, there shall be a means of immediate communication with the rig floor, and the equipment shall be continually manned.

6.3 *Mud Quantities.* The lessee shall include, with his Application for Permit to Drill, a tabulation of well depth versus minimum quantities of mud material, including weighting material, to be maintained at the drill site. The minimum quantities of mud material required shall be based on the following:

a. The volume required to replace the calculated capacity of the downhole and active surface mud system.

b. The quantity of weighting material required to overcome the highest-anticipated formation pressure.

When the mud quantity required exceeds the storage capacity of the drilling facility, the lessee shall maintain maximum mud inventories and must receive approval from the District Supervisor of the lessee's plans to resupply mud inventories in the event of an emergency. The plan shall include an estimate of the time required for delivery of the mud supplies.

Daily inventories of mud materials, including weighting material, shall be recorded and maintained at the well site. Drilling operations shall be suspended in the absence of minimum quantities of mud material specified in the table or as modified in the approved plan.

7. *Supervision, Surveillance, and Training*

7.1 *Supervision.* A representative of the operator shall provide onsite supervision of drilling operations on a 24-hour basis.

7.2 *Surveillance.* From the time drilling operations are initiated and until the well is completed or abandoned, a member of the drilling crew or the toolpusher shall maintain rig-floor surveillance continuously, unless the well is secured with blowout preventers, bridge plugs, or cement plugs.

7.3 *Training.* By December 1, 1979, lessee and drilling contractor personnel shall be trained and qualified in accordance with the provisions of the USGS Outer Continental Shelf Standard, "Training and Qualifications of Personnel in Well-Control Equipment and Techniques for Drilling on Offshore Locations," No. T 1, (GSS–OCS–T 1), First Edition, December 1977, and subsequent revisions thereto.

Any driller, toolpusher, or operator's representative who received training in well-control operations between December 1, 1975, and December 1, 1979, will be credited with having met the training requirements of GSS–OCS–T 1.

After December 1, 1979, in order to maintain qualification, employees must successfully complete a USGS-approved refresher course annually and repeat the basic well-control course every 4 years, as described in the provisions of GSS–OCS–T 1. Credit for these courses shall be obtained from USGS-approved schools.

The refresher course shall be completed within 45 days of the student's anniversary date. The anniversary date is established upon the student's successful completion of a basic course in well control.

Records shall be maintained at the drill site for the affected personnel, indicating the specific training and refresher courses sucessfully completed, the dates of completion, and the names and dates of the courses.

In those Areas which are subject to subfreezing conditions, the lessee shall ensure that personnel responsible for maintenance of the blowout-preventer stack, the associated-control equipment, and the hydraulic-control fluids shall be instructed in the proper procedures to prevent freezing of the hydraulic-control fluids in the control system and the fluids in the choke and kill lines.

8. *Hydrogen Sulfide.* When drilling operations are planned which will penetrate reservoirs known or expected to contain hydrogen sulfide, (H_2S), or in those areas where the presence of H_2S is unknown, or upon encountering H_2S, the preventive measures and the operating practices set forth in U.S. Geological Survey Outer Continental Shelf Standard, "Safety Requirements for Drilling Operations in a Hydrogen Sulfide Environment," No. 1 (GSS–OCS–1) Second Edition, June 1979, or subsequent revisions thereto, shall be followed.

9. *Critical Operations and Curtailment Plans*

Gulf of Mexico

Certain operations performed in drilling are more critical than others with respect to well control, and for the prevention of fire, explosion, oil spills and other discharges or emissions. The lessee shall file with the District Supervisor, for approval, a Critical Operations and Curtailment Plan to be followed while conducting drilling operations in each District area. This plan shall include:

a. The guidelines the operator will follow to assure coordination, control, and, if necessary, curtailment of drilling activities.

b. The name of the person who has overall responsibility, as the person in charge at the site, for safety of drilling operations.

c. An outline of any additional safety or antipollution measures that are required when conducting critical drilling operations.

The lessee shall review the plan at least annually. The lessee shall notify the District Supervisor of the results of this review. Any amendments or modifications of the plan are subject to the approval of the District Supervisor.

Pacific, Gulf of Alaska, and Atlantic

Certain operations performed in drilling are more critical than others with respect to well control, and for the prevention of fire,

explosion, oil spills, and other discharges or emissions. The lessee shall file with the District Supervisor, for approval, a Critical Operations and Curtailment Plan to be followed while conducting drilling operations on each lease. This plan shall include:

a. A list or description of the critical drilling operations that are, or are likely to be, conducted on the lease. This list or description shall specify the operations to be ceased, limited, or not to be commenced under given circumstances or conditions. This list shall include operations such as:

(1) Drilling in close proximity to another well.

(2) Drill-stem testing.

(3) Running and cementing casing.

(4) Cutting and recovering casing.

(5) Logging or wireline operations.

(6) Well-completion operations.

(7) Moving the drilling vessel off location in an emergency, repositioning the vessel on location, and reestablishing entry into the well.

b. A list or description of circumstances or conditions under which such critical operations shall be curtailed. This list or description shall be developed from all the factors and conditions relating to the conduct of operations on the lease, and shall consider but not necessarily be limited to the following:

(1) Whether the drilling operations are to be conducted from mobile or fixed platforms.

(2) The availability and capability of containment and cleanup equipment and spill-control system response time.

(3) Abnormal or unusual conditions expected to be encountered during drilling operations.

(4) Known or anticipated meteorological or oceanographical conditions.

(5) Availability of personnel and equipment for particular operations to be conducted.

(6) Other factors peculiar to the particular lease under consideration.

c. The name of the person who has overall responsibility, as the person in charge at the site, for safety of drilling operations.

When any circumstance or condition listed or described in the plan occurs or other operational limits are encountered, the lessee shall notify the District Supervisor and shall curtail the critical operations as set forth under 9a.

Deviations from the plan shall require prior approval of the District Supervisor. If emergency action requires deviation from the plan, the District Supervisor shall be notified as soon as possible.

The lessee shall review the plan at least annually. The lessee shall notify the District Supervisor of the results of this review. Any amendments or modifications of the plan are subject to the approval of the District Supervisor.

10. *Field Drilling Rules.* When sufficient geological and engineering information is obtained as a result of drilling operations, the lessee may make an application or the Supervisor may require an application for the establishment of field drilling rules. After field drilling rules have been established by the Supervisor, development wells shall be drilled in accordance with these rules and the requirements of this Order which are not affected by such rules.

11. *Departures.* All departures from the requirements specified in this Order shall be subject to approval pursuant to 30 CFR 250.12(b).

Approved:

Don E. Kash,

Chief, Conservation Division.

OCS Order No. 3

Subparagraph 1.1

Comments. It was suggested that the phrase "or to prevent migration of fluids in the well bore" is redundant.

Discussion. The intent of OCS order No. 3 is to prevent the migration of formation fluids within the well bore. The subparagraph was revised by changing the title to "Isolation of Zones in Open Hole." The second sentence was revised as follows:

"The placement of additional cement plugs to prevent the migration of formation fluids in the well bore may be required by the District Supervisor."

This revision clarifies the intent and recognizes the District Supervisor's authority to require additional plugs.

Subparagraph 1.4

Comments. It was suggested that the phrase "cannot be used" is ambiguous and that the phrase should read "if the foregoing preferred methods are not used."

Discussion. The subparagraph was revised to eliminate the phrase "if the foregoing methods cannot be used." A new lead-in sentence was added as follows:

"If casing is cut and recovered leaving a stub, one of the following methods shall be used to plug the casing stub."

Two new subparagraphs were added, 1.4.1 and 1.4.2, to differentiate between the requirements of stubs terminating inside casing and stubs terminating below the casing strings.

Subparagraph 1.7

Comments. It was suggested that all plugs should be verified in the same manner as the first plug below the top plug.

Discussion. OCS Order No. 3 requires the testing of the first plug below the surface plug. Past well history has indicated that it is not necessary to test the plugs below the surface plug. The subparagraph was reorganized by adding a new lead-in sentence stating that the plug shall be verified by one of the following methods: "a" or "b". The methods were segregated into the following segments: "a" and "b". The revision also makes it clear that if cement is placed above a bridge plug or a retainer, the cement need not be tested.

Subparagraph 1.9

Comments. There was a divergence of opinion on the wording which provides flexibility for the District Supervisor to approve the removal of casing at depths less than 5 meters (16 feet) below the ocean floor.

Discussion. OSC Order No. 3 states that the approval of the Supervisor is required to remove casing at depths less than 5 meters (16 feet) "after a review of data on the ocean-bottom conditions." There have been instances where it was impossible to remove casing which had been severed at 5 meters (16 feet). In the Gulf of Alaska, a casing string was severed at 5 meters (16 feet) and could not be pulled with a force of 181,437 kilograms (400,000 pounds). The pipe was then cut at 2 meters (6 feet) below the ocean floor and was successfully pulled with a force of 136,078 kilograms (300,000 pounds). This problem is prevalent where hard bottoms exist. In a hard bottom where erosion of the ocean floor is unlikely, the depth of the severance is not critical. In a soft bottom which is subject to erosion, there would be no difficulty in removing the casing at 5 meters (16 feet) below the ocean floor.

Paragraph 2

Comments. No written comments received.

Discussion. The paragraph was revised, however, by the Conservation Division staff after it was realized that the requirement for setting a cement plug in the open hole of a temporarily abandoned drilling well has caused an unintentional sidetrack while trying to drill out of the 100-foot cement plug below the casing. This can easily occur when the formation is softer than the cement plug. Such sidetracking and the resultant dog leg are highly undesirable. The following two sentences were added to the paragraph:

"When a drilling well is temporarily abandoned, a bridge plug or a cement plug shall be set at the base of the deepest casing string. If a cement plug is set, it is not necessary for the cement plug to extend below the casing shoe into the open hole."

It was also suggested by Conservation Division personnel that this paragraph should address the requirements for the marking of casing stubs which extend above the ocean floor. The last sentence of the paragraph was revised as follows:

"When a casing stub extends above the ocean floor, the operator shall comply with the following requirements:

"a. A mechanical, retrievable, or permanent bridge plug, or a cement plug at least 30 meters (98 feet) in length shall be set in the casing between 5 and 60 meters (16 and 197 feet) below the ocean floor.

"b. The requirements of OCS Order No. 1, paragraph 4, 'Identification of Subsea Objects.' "

United States Department of the Interior; Geological Survey Conservation Division

OCS Order No. 3, Effective July 1, 1979; Plugging and Abandonment of Wells

This Order is issued pursuant to the authority prescribed in 30 CFR 250.11 and in accordance with 30 CFR 250.15. The operator shall comply with the following minimum plugging and abandonment procedures which have general application to all wells drilled for oil or gas. Plugging and abandonment operations shall not be commenced prior to obtaining approval from the appropriate District Supervisor. Oral or telegraphic approvals shall be in accordance with 30 CFR 250.13.

1. *Permanent Abandonment*

1.1 *Isolation of Zones in Open Hole.* In uncased portions of wells, cement plugs shall be spaced to extend 30 meters (98 feet) below the bottom to 30 meters (98 feet) above the top of any oil, gas, and freshwater zones so as to isolate them in the strata in which they are found and to prevent them from escaping into other strata or the surface. The placement of additional cement plugs to prevent the migration of formation fluids in the well bore may be required by the District Supervisor.

1.2 *Isolation of Open Hole.* Where there is open hole below the casing, a cement plug shall be placed in the deepest casing string in accordance with "a" or "b" below. In the event lost circulation conditions have been experienced or are anticipated, a permanent-type bridge plug may be placed in accordance with "c" below:

a. A cement plug set by the displacement method so as to extend a minimum of 30 meters (98 feet) above and 30 meters (98 feet) below the casing shoe.

b. A cement retainer with effective back-pressure control set not less than 15 meters (49 feet) nor more than 30 meters (98 feet) above the casing shoe, with a cement plug calculated to extend at least 30 meters (98 feet) below the casing shoe and 15 meters (49 feet) above the retainer.

c. A permanent-type bridge plug set within 45 meters (148 feet) above the casing shoe with 15 meters (49 feet) of cement on top of the bridge plug. This bridge plug shall be tested in accordance with subparagraph 1.7 prior to placing subsequent plugs.

1.3 *Plugging or Isolating Perforated Intervals.* A cement plug shall be set by the displacement method opposite all open perforations (perforations not squeezed with cement) extending a minimum of 30 meters (98 feet) above and 30 meters (98 feet) below the perforated interval or down to a casing plug, whichever is less. In lieu of setting a cement plug by the displacement method, the following two methods are acceptable, provided the perforations are isolated from the hole below:

a. A cement retainer with effective back-pressure control set not less than 15 meters (49 feet) nor more than 30 meters (98 feet) above the top of the perforated interval with a cement plug calculated to extend at least 30 meters (98 feet) below the bottom of the perforated interval and 15 meters (49 feet) above the retainer.

b. A permanent-type bridge plug set within 45 meters (148 feet) above the top of the perforated interval with 15 meters (49 feet) of cement on top of the bridge plug.

1.4 *Plugging of Casing Stubs.* If casing is cut and recovered leaving a stub, one of the following methods shall be used to plug the casing stub.

1.4.1 *Stub Termination Inside Casing String.* A stub terminating inside a casing string shall be plugged by one of the following methods:

a. A cement plug set so as to extend 30 meters (98 feet) above and 30 meters (98 feet) below the stub.

b. A cement retainer set 15 meters (49 feet) above the stub with 45 meters (148 feet) of cement set below and 15 meters (49 feet) above.

c. A permanent bridge plug set 15 meters (49 feet) above the stub and capped with 15 meters (49 feet) of cement.

1.4.2 *Stub Termination Below Casing String.* If the stub is below the next larger string, plugging shall be accomplished in accordance with either subparagraph 1.1 or 1.2.

1.5 *Plugging of Annular Space.* Any annular space comunicating with any open hole and extending to the ocean floor shall be plugged with cement.

1.6 *Surface Plug.* A cement plug at least 45 meters (148 feet) in length, with the top of the plug 45 meters (148 feet) or less below the ocean floor, shall be placed in the smallest string of casing which extends to the ocean floor.

1.7 *Testing of Plugs.* The setting and location of the first plug below the surface plug shall be verified by one of the following methods:

a. By placing a minimum pipe weight of 6,800 kilograms (15,000 pounds) on the cement plug, cement retainer, or bridge plug. The cement placed above the bridge plug or retainer need not be tested.

b. By testing the plug with a minimum pump pressure of 6,900 kPa (1,000 psi) with no more than a 10-percent pressure drop during a 15-minute period.

1.8 *Mud.* Each of the respective intervals of the hole between the various plugs shall be filled with mud fluid of sufficient density to exert hydrostatic pressure exceeding the greatest formation pressure encountered while drilling the intervals between the plugs.

1.9 *Clearance of Location.* All casing, wellhead equipment, and piling shall be removed to a depth of at least 5 meters (16 feet) below the ocean floor or at a depth approved by the District Supervisor after a review of data on the ocean-bottom conditions. The operator shall verify that the location has been cleared of all obstructions.

2. *Temporary Abandonment.* Any drilling well which is to be temporarily abandoned shall be mudded and cemented as required for permanent abandonment except for the requirements in subparagraphs 1.6 and 1.9. When a drilling well is temporarily abandoned, a bridge plug or a cement plug shall be set at the base of the deepest casing string. If a cement plug is set, it is not necessary for the cement plug to extend below the casing shoe into the open hole. When a casing stub extends above the ocean floor, the operator shall comply with the following requirements:

a. A mechanical, retrievable, or permanent bridge plug, or a cement plug at least 30 meters (98 feet) in length shall be set in the casing between 5 and 60 meters (16 and 197 feet) below the ocean floor.

b. The requirements of OCS Order No. 1, paragraph 4, "Identification of Subsea Objects."

3. *Departures.* All departures from the requirements specified in this Order shall be subject to approval, pursuant to 30 CFR 250.12(b).

Approved:

Don E. Kash,

Chief, Conservation Division.

OCS Order No. 4

Preamble

Comments. It was suggested that the fourth sentence of the Preamble should be revised by changing the word "may" to "shall" and by adding the phrase "and reasonable and prudent efforts are being made to comply with the requirements."

Discussion. The intent of the Preamble was not to make it mandatory that the Supervisor grant a suspension of production. The Supervisor has specific guidelines to be used in his determination of the approval or the denial of a request for a suspension of production. The Supervisor has the discretion of approving or disapproving requests for suspensions of production based on these guidelines.

New Paragraph 1

Comments. No comments received.

Discussion. A new paragraph 1 was added to require the timely submittal of an application for determination of well producibility. This application is to be submitted to the District Supervisor to request his determination of well's capability of producing oil or gas in paying quantities for each new well drilled on a non-producible lease. The application must be submitted within 60 days after the drilling rig has moved from the well. This requirement allows the Supervisor to evaluate the diligence of the lessee in the development of the lease at an early stage. All subsequent paragraphs of the Order were renumbered.

Paragraphs 1, 2, and 3

Comments. Two commenters indicated that the intent of the Order was not clear. A lack of clarity was cited in the paragraphs which allow the demonstration of production capability through production tests, logs, or other proven formation evaluation techniques.

Discussion. We agree with these comments and have reorganized the Order as follows:

Paragraph 2, "Criteria for the Determination of Well Producibility," was written to incorporate and clarify the intent of the last sentence of the proposed Preamble. This new introductory paragraph states that the Supervisor shall prescribe which of certain criteria is to be used to determine the capability of a well to produce in paying quantities. This language makes it clear that the determination will be based either on production tests as outlined in subparagraph 2.1 or on a production capability determination as outlined in subparagraph 2.2.

The content of the original paragraph 4, "Witnessing and Results," was incorporated into the lead-in sentence of subparagraph 2.1, "Production Tests." The requirements for production tests for oil wells and gas wells, which were contained in the original paragraphs 1 and 2, were listed in separate subparagraphs "a" and "b" of subparagraph 2.1.

The original paragraph 3, "Production Capability," was retitled as a new paragraph 2.2, "Production Capability Determination." For the Gulf of Mexico Region, it has been determined that certian well data may be considered as reliable evidence that a well is capable of producing oil or gas in paying quantities; therefore, the Gulf of Mexico lists the type of data which the District Supervisor would evaluate in his determination of production capabilities. The Supervisor has the discretion to make a determination to accept this data or to require a production test. Since the Pacific, Gulf of Alaska, and Atlantic Areas do not have sufficient production history and data upon which to base a judgment on the reliability of well data as an indication of production capability, the production capability determination requirement was worded as follows:

"When the District Supervisor determines that open-hole evaluation data, such as wireline formation tests, drill stem tests, core data, and logs, have been demonstrated as reliable in a geologic area, such data may be considered as acceptable evidence that a well is capable of producing in paying quantities."

Comments. It was suggested that the proposed Appendix for the Gulf of Mexico does not parallel the requirements of the Order because the Order requires a flow test plus an analysis of pertinent engineering, geologic, and economic data to determine whether a well is capable of producing in paying quantities.

Discussion. As previously stated, the revised introductory sentence for paragraph 2 makes it clear that the Supervisor will determine whether production tests or well data are to be used in the determination of production capability.

Comments. It was suggested that the proposed subparagraph 3A(2) of the Appendix for the Gulf of Mexico should allow for the consideration of an apparent water resistivity ratio (Rwa) of 3:1 as an alternative to a minimum true resistivity ratio of 5:1 in a determination of production capability.

Discussion. The apparent water resistivity ratio is not considered a reliable indicator. The Rwa may be erroneous due to the presence of gas, shale, whole washout, or uncompacted sediments. The requirement for the Gulf of Mexico was not revised.

Comments. It was suggested that the words "absolutely," "conclusively," and "water free" are too positive for the intent of the proposed subparagraph 3C for the Gulf of Mexico Region.

Discussion. We agree with these comments and have deleted the words from the requirement for the Gulf of Mexico Region.

United States Department of the Interior; Geological Survey Conservation Division

OCS Order No. 4, Effective July 1, 1979; Determination of Well Producibility

This Order is issued pursuant to the authority prescribed in 30 CFR 250.11 and in accordance with 30 CFR 250.12. An OCS lease provides for extension beyond its primary term for as long as oil or gas may be produced from the lease in paying quantities. The term "paying quantities" as used herein means production of oil and gas in quantities sufficient to yield a return in excess of operating costs. An OCS lease may be maintained beyond the primary term, in the absence of actual production, when a suspension of production has been approved in accordance with 30 CFR 250.12.

1. *Application for Determination of Well Producibility.* An application shall be submitted to the District Supervisor for the determination of every new well's capability of producing until a well, drilled on the lease, has been determined to be capable of producing oil or gas in paying quantities. The application shall be submitted within 60 days after the drilling rig has been moved from the well.

2. *Criteria for the Determination of Well Producibility.* The Supervisor shall prescribe which of the following criteria is to be used to determine the capability of a well to produce in paying quantities.

2.1 *Production Tests.* All tests must be witnessed by an authorized representative of the U.S. Geological Survey. Test data accompanied by operator's affidavit, or third-party test data, may be accepted in lieu of a witnessed test, provided approval is obtained from the District Supervisor prior to the performance of the test. All tests must conform to the following minimum requirements:

a. A production test for oil wells of at least 2 hours' duration following stabilization of flow.

b. A deliverability test for gas wells of at least 2 hours' duration following stabilization of flow or a 4-point back-pressure test.

2.2 *Production Capability Determination.*

Gulf of Mexico

The following may be considered as reliable evidence that a well is capable of producing oil or gas in paying quantities:

a. A resistivity log of the well showing a minimum of 15 feet of producible sand in one section that does not include any interval which appears to be water-saturated. All of the section counted as producible shall exhibit the following properties:

(1) Electrical spontaneous potential exceeding 20 negative millivolts beyond the shale base line. If mud conditions prevent a 20-negative-millivolt reading beyond the shale base line, a gamma ray log deflection of at least 70 percent of the maximum gamma ray deflection in the nearest clean water-bearing sand may be substituted.

(2) A minimum true resistivity ratio of the producible section to the nearest clean water-bearing sand of at least 5:1.

(3) A porosity log indicating porosity in the producible section.

b. Sidewall cores and core analyses which indicate that the section is capable of producing oil or gas.

c. The aforementioned criteria will ascertain that a well is producible. However, recognizing the fact that all geologic formations in the Gulf of Mexico Region do not possess the same physical properties and, therefore, do not lend themselves to one single method of log analysis, the U.S. Geological Survey may, at its discretion, accept sound log-interpretation techniques which demonstrate that a well would produce hydrocarbons in a particular area, even though the well might not qualify under items "a" and "b". The lessee can support the determination of well producibility by submitting further evidence such as wireline formation tests and/or mud logging analyses.

Pacific, Gulf of Alaska, and Atlantic

When the District Supervisor determines that open-hole evaluation data, such as wireline formation tests, drill stem tests, core data, and logs, have been demonstrated as reliable in a geologic area, such data may be considered as acceptable evidence that a well is capable of producing in paying quantities.

3. *Departures.* All departures from the requirements specified in this Order shall be subject to approval, pursuant to 30 CFR 250.12(b).

Approved:

Don E. Kash,

Chief, Conservation Division.

OCS Order No. 5

Title

Comments. No comments received.

Discussion. The title of the Order was changed from "Subsurface Safety Devices and Surface Safety Systems" to "Production Safety Systems." The new title is consistent with the content of the Order.

Preamble

Comments. One commenter stated that "We do not believe the wording in the preamble to this Order is in accord with the objectives of the Memorandum of Understanding (MOU) between DOI and DOT which delineates the jurisdictional limits of DOI–USGS and DOT–OPSO for transmission pipelines and facilities boarding producer's platforms. The intent and the language of the MOU should be taken into consideration in delineation of jurisdiction."

Discussion. This Order is concerned with well and platforms safety devices; the objectives of the MOU between DOT and DOI are within the purview of OCS Order No. 9, "Oil and Gas Pipelines."

Paragraph 1

Comments. It was suggested that paragraph 1 be revised "to read as follows: Technological improvement. The operator is encouraged to continue development of new and improved safety device technology, and as technological research, progress, and product improvement result in increased effectiveness of existing safety devices or the development of new devices or systems, such devices or systems may be used or required. For new subsurface-safety devices or systems, field testing shall be approved by the District Supervisor, and applications for routine use shall include evidence that the device or system has been field tested at least once each month for a minimum of 6 consecutive months, and that each test indicated proper operation."

Discussion. Only the first sentence of this suggestion was adopted to be consistent with

the quality-assurance paragraph of this Order. The USGS encourages the development of new safety devices and systems; however, it is intended that new safety devices be tested according to the qualification test requirments of ANSI/ASME SPPE–1–1977 (formerly ANSI/ASME OCS–1–1977). (Refer to subparagraphs 2a and 2b.) It is not the objective to have uncertified and unproved devices field tested. The field testing of uncertified and unproved safety devices requires a departure in accordance with paragraph 10 of this Order.

Comments. Another commenter noted that "if the technology improves in a specific area, the USGS should be in a position to require its use." It was also contended that the best available equipment should be used on "* * * all existing operations (where practicable) and on all new operations, where necessary to protect public health, safety or the environment."

Discussion. The objectives and requirements of paragraphs 1 and 4 of this Order are consistent with these comments.

Paragraph 2

Comments. No comments received.

Discussion. Since the quality assurance and performance requirements of the original subparagraph 2.3.1 are applicable to both surface- and subsurface-safety devices, it was determined that these requirements should be listed under a separate paragraph rather than a subparagraph concerned with subsurface-controlled subsurface-safety devices. Therefore, the requirément was revised and retitled as a new paragraph 2, "Quality Assurance and Performance of Safety and Pollution-Prevention Equipment." The subsequent paragraphs were renumbered. The revised subparagraph refers to subparagraph 3.2 for compliance dates for subsurface-safety valves and to 4.3 for compliance dates for surface-safety valves.

Comments. It was suggested that the following "grandfather clause" should be incorporated into the first sentence of paragraph 2 (2.3.1), "All subsurface-safety devices purchased for installation after the date of this Order shall * * *." It was contended that "a grandfather clause is needed to prevent the wasteful replacement of these devices."

Another commenter stated that "These sections (2.3.1 and 2.3.2) require that the operator shall conform to API Specification 14A and API Recommended Practice (RP) 14B in selection, installation, and testing of subsurface safety devices."

It was also noted that "While the subsurface safety devices we currently use in our operations meet the intent of 14A and 14B, a rigorous analysis would find them lacking in certain minor areas. The forced replacement of these perfectly acceptable devices is unnecessary and wasteful."

Discussion. The dates for compliance with API Specification 14A and API RP 14B are stated in subparagraphs 3.2 and 3.3, respectively. Provision has been made for existing wells. It is not the intent of the USGS to cause unnecessary replacement of these subsurface devices.

Subparagraph 3.1

Comments. It was suggested that a date change be made to Appendix I, Gulf of Mexico as follows: "Change 'June 5, 1972' in six places in 2(a), 2(a)(1), 2(a)(2), 2(b), 2(b)(1), and 2(b)(2)." It was contended that "Existing OCS Order No. 5 for the Gulf of Mexico Area would have allowed installation of a subsurface-controlled safety device in a well initially completed or for which tubing was removed and reinstalled between June 5, 1972, the effective date of the Order, and December 1, 1972, the compliance date given in the Order. Any well which was so completed and which has not had the tubing pulled and reinstalled since December 1, 1972, could still have a subsurface-controlled subsurface-safety device and be in compliance with OCS Order No. 5. The use of the June 5, 1972, date in subparagraphs 2(a), 2(a)(1), and 2(a)(2) of the proposed Order would required that these devices be immediately changed even if the tubing does not need to be pulled and reinstalled. Revising the date in these three subparagraphs to be December 1, 1972, would retain the status quo on these wells."

Another commenter suggested that subparagraph 3.4 (2.3) be revised as follows: *"Except as provided below and in subparagraph 2.4,* all tubing installations open to and capable of producing from hydrocarbon-bearing zones shall be equipped with a surface-controlled subsurface safety device. The surface controls may be located on site or remotely. *Wells with a shut-in tubing pressure of 4,000 psig or greater shall be equipped with a subsurface-controlled subsurface safety device in lieu of a surface-controlled subsurface safety device. A surface-controlled subsurface safety device may be installed if approved by the Supervisor. When the shut-in tubing pressure declines below 4,000 psig, a surface-contolled subsurface safety device shall be installed when the tubing is first removed and reinstalled."*

It was contended that "The suggested revision incorporates the exception in existing Gulf of Mexico OCS Order No. 5 for high pressure wells into the National Order. The Gulf of Mexico Order recognizes the limited availability of surface-controlled subsurface safety valves for high pressure wells. We know of no justification for deviating from the Gulf of Mexico requirements, which have been proven by experience to provide adequate safety."

Discussion. The comments summarized above are interrelated; therefore, this discussion addresses several concerns.

It has been determined that the pressure criteria which were proposed in the original Gulf of Mexico Appendix are applicable to all Areas; therefore, subparagraph 3.1 (2.1) has been rewritten as an "all Areas" requirement. This determination is based on an assessment of technical problems which have been encountered in the control systems of subsurface-controlled subsurface-safety valves in wells with shut-in tubing pressures greater than 4,000 psig in the Gulf of Mexico Area.

It is recognized that December 1, 1972, is the effective date for the requirements of subparagraph 3.1 for the Gulf of Mexico Area; however, it is not necessary to stipulate a retroactive effective date for any Area. The existing requirements for all Areas are legally binding until the requirements are superseded by the revised order, which will become effective on July 1, 1979.

The subparagraph has been segregated into interdependent categories as follows:

(1) Wells and tubing installations completed after the effective date of the Order.

(2) Wells and tubing installations completed prior to the effective date of the Order.

(3) Shut-in tubing pressures greater than 4,000 psig.

(4) Shut-in tubing pressures less than 4,000 psig.

Comments. It was suggested that the first sentence of subparagraph 3.1 (2.1), "Installation," be changed to: "All tubing installations open to and capable of producing from hydrocarbon-bearing zones shall be equipped with a subsurface safety device unless, after application and justification, the well is determined to be incapable of flowing *oil or gas.*"

It was contended that "The suggested addition of the phrase 'oil or gas' to the end of this sentence retains a requirement in the existing Gulf of Mexico Area OCS Order No. 5. There is no justification for requiring subsurface safety devices in wells which are incapable of flowing hydrocarbons.

"The USGS has shown no justification for deviating from the Gulf of Mexico Order, which has been proven by experience to provide adequate safety."

Discussion. This suggestion was not adopted. The intent is to require subsurface-safety devices in wells which are capable of flowing saltwater. High-salinity and high-temperature saltwater are also pollutants.

Subparagraph 3.2

Comments. No comments received.

Discussion. A new subparagraph 3.2 was written to incorporate a "grandfather clause" and to specify a date for compliance with "API Specification for Subsurface Safety Valves," API Spec 14A. This requirement was formerly in the proposed subparagraph 2.3.1. Refer to the discussion for paragraph 2.

Former Subparagraph 2.2

Comments. No comments received.

Discussion. The originally proposed subparagraph 2.2 was deleted and the requirements were incorporated into subparagraph 3.3.

Subparagraph 3.3

Comments. No comments received.

Discussion. A new subparagraph 3.3, "Design Installation and Operation," was written to consolidate the requirements of the original subparagraphs 2.2 and 2.3.2, and to add a "grandfather clause" for compliance with the requirements of API RP 14B. The test frequency requirement which was formerly in the original subparagraph 2.3.2 has been included in subparagraph 3.4.1. The subsequent subparagraphs were renumbered.

Subparagraph 3.4

Comments. It was recommended that the references to appendices III, IV, or V are not necessary because the requirements for "Subfreezing Operations" could be condensed into a one-sentence statement and placed in the Order.

Discussion. This suggestion was adopted.

Subparagraph 3.4.1

Comments. A large number of comments addressed subparagraph 3.4.1 (2.3.2), "Installation and Testing," objecting to the test frequency of surface-controlled subsurface-safety valves. The requirement is quoted: "* * * installed in a well shall be tested in place for proper operation when installed, or reinstalled, at least monthly for the next six months, and quarterly thereafter." The consensus was that the proposed testing periods were too frequent, burdensome, and unnecessary.

Conversely, one commenter stated that "Testing frequency should be increased over the life of the device, however, since equipment tends to get less reliable with age, rather than more reliable. Again we see reliance on API Recommended Practice, with no justification provided."

Discussion. After considering the above comments, the test frequency was changed to "* * * at least monthly for the first 3 months, and thereafter at intervals not exceed 6 months." It is believed that the initial three monthly tests are necessary to establish reliability; the subsequent semiannual tests are sufficient to verify functional operation for the remainder of the service-life of the device. The subparagraph was also revised to require the valves to be tested in accordance with Appendix E of API RP 14B. This appendix describes the test procedure.

Justification for reliance on API documents has been previously discussed in the Comments/Discussion section of OCS Order No. 2, paragraph 3.

Subparagraph 3.5 and 3.5.1

Comments. No comments received.

Discussion. In the proposed National OCS Order, subparagraph 2.4, "Subsurface-Controlled Subsurface-Safety Devices," there was no requirement for subsurface-controlled subsurface-safety devices for any Area of the OCS except the Gulf of Mexico Area. Our review of the Order indicated that the Order should provide for the installation of subsurface-controlled subsurface-safety valves in wells from single well and multiwell satellite caissons or jackets and ocean floor completions. It was concluded that the Order should allow the optional use of these valves instead of surface- or other remote-controlled subsurface-safety valves for the satellite or subsea-type well completions. This option is necessary because it may be impractical to use surface-controlled subsurface-safety valves in satellite caisson and subsea-type completions. A new subparagraph 3.5.1, "Inspection and Maintenance of Subsurface-Controlled Subsurface-Safety Valves," was also added to provide assurance of the proper functioning of the valves.

The closing-pressure and the flowrate design criteria which were specified in subparagraph 2d of the original appendix for the Gulf of Mexico OCS Area were deleted. These requirements are not necessary because these design criteria are specified in API RP 14B.

The new subparagraph 3.3 references API RP 14B as a requirement.

Subparagraph 3.6

Comments. The comments on the original subparagraphs 2.5, "Shut-in Wells," and 2.7, "Tubing Plugs," indicated that these subparagraphs are interrelated and, therefore, should be combined into a new paragraph entitled "Tubing Plugs in Shut-in Wells."

Discussion. The content of the original subparagraphs 2.5 and 2.7 were edited and combined into the new subparagraph 3.6, "Tubing Plugs in Shut-in Wells."

Comments. One commenter referred to subparagraph 3.6 (2.5), stating that "It appears that the pump-through type of retrievable plug may be more susceptible to leaks than a simple blanking plug. The reason for specifying this type of plug is unclear. Provision should be made for alternative plugging techniques."

Discussion. A pump-through type of tubing plug is required because this type of plug permits control of the well without removing the plug.

Comments. A number of commenters objected to subparagraph 3.6 (2.7) concerning the minor leakage of tubing plugs. One commenter proposed that the second and third sentences be revised as follows: *"If sustained liquid flow exceeds 400 cc/min, or gas flow exceeds 15 cu ft/min,* the plug shall be removed, repaired, and reinstalled or an additional tubing plug may be installed in lieu of removal and repair."

It was contended that "The very minimal flow rates allowed by the existing Gulf of Mexico Order permit confirmation that the plug is holding without having to wait for hours until *all* flow stops. Temperature fluctuations will also indicate very small flow rates (fluid expansion) without any leak through the plug."

Discussion. The tubing-plug-leakage factor has been reevaluated, and the suggestions were adopted.

Subparagraph 3.7

Comments. One commenter suggested that subparagraph 3.7 (2.6), "Injection Wells," be revised as follows: "Surface-controlled subsurface-safety devices, *except as specified in subparagraph 2.4,* shall be installed in all injection wells unless, after application and justification, it is determined that the well is incapable of flowing *oil or gas.*"

It was contended that "Existing OCS Order No. 5 for the Gulf of Mexico Area allows the use of subsurface-controlled subsurface-safety devices in some older wells as long as the tubing has not been removed and reinstalled. The proposed order would require that all of these subsurface-controlled valves be replaced immediately with surface-controlled valves. The suggested revision would maintain the status quo and would only require replacement of the subsurface-controlled valve with a surface-controlled valve when the tubing is pulled and reinstalled on these older wells."

Discussion. The subparagraph was revised to segregate the requirements into two categories: (1) wells which were placed in injection service after the effective date of this order and (2) wells which were placed in injection service prior to the effective date of this order. This requirement is consistent with the existing OCS Order for the Gulf of Mexico which contains a compliance date of December 1, 1972. This requirement is also consistent with the existing requirements for the other Areas of the OCS. It is not necessary to specify specific compliance dates for each Area of the OCS because the existing orders are binding until the requirements are superseded by the revised Order, which will become effective July 1, 1979.

The phrase "oil or gas" was not added to the Order because injection wells often contain residual volumes of oil and/or entrained gas. These residual volumes collect in the well bore when injection is terminated; therefore, such injection wells are capable of oil or gas. High-salinity and high-temperature saltwater are also pollutants.

Subparagraph 3.8

Comments. No comments received.

Discussion. The subparagraph was revised to clarify the requirements for reporting the temporary removal of subsurface-safety devices and the requirements for attending the well when the subsurface-safety device has been removed.

Subparagraph 3.9

Comments. No comments received.

Discussion. The title of this subparagraph has been changed from "Additional Protective Equipment" to "Additional Safety Equipment" to more accurately describe the intent of the subparagraph.

Comments. Several commenters addressed subparagraph 3.9 (2.9), "Additional Safety Equipment," and suggested that the first sentence be revised as follows: "All tubing installations *made after June 5, 1972,* in which a wireline- or pumpdown-retrievable subsurface-safety device is to be installed shall be equipped with a landing nipple, with flow couplings, or other protective equipment, above and below, to provide for setting of the subsurface-safety device."

The commenter also noted that "Tubing installations made before June 5, 1972, in the Gulf of Mexico Area do not have to be equipped with a landing nipple and related equipment under the provisions of the current Gulf of Mexico OCS Order No. 5. The proposed Order would require that these wells be so equipped. The suggested revision would retain the status quo for these tubing installations."

Discussion. The subparagraph was revised by adding the clause "after the effective date of this Order." This revision is compatible with the existing requirements for all Areas of the OCS. Refer to the rationales pertaining to post effective dates in the discussion of subparagraph 3.1.

Comments. It was suggested that the second sentence of subparagraph 3.9 (2.9) be revised as follows: "All wells in which a subsurface-safety device or tubing plug is installed shall have the tubing-casing annulus packed off above the uppermost open perforations. *Unless otherwise approved by the District Supervisor, all tubing installations made after the effective date of this Order and in which a subsurface-safety device or tubing plug is installed* shall have the tubing-casing annulus packed off at least 30 meters (98 feet) below the measured or calculated top of cement on the production string or the intermediate string."

Discussion. The second sentence was deleted because the requirements will be included in a revision of OCS Order No. 6, "Well Completions and Workover Operations."

Comments. Another commenter suggested that the following phrase be added to the end of the last sentence of subparagraph 3.9 (2.9): "or of an independent remote shut-in system."

Discussion. In order to clarify the intent, the last sentences have been revised as follows: "The control system for all surface-controlled subsurface-safety valves shall be an integral part of the platform Emergency Shutdown System (ESD) as defined in API RP 14C Appendix C, Section C1. In addition to the activation of the ESD system, by manual action on the platform, the system may be activated by a signal from a remote location. Surface-controlled subsurface-safety valves shall close in response to shut-in signals from the ESD system or the fire loop, or both."

Former Subparagraph 2.10

Comments. No comments received.

Discussion. The proposed subparagraph 2.10, "Departures," was deleted because departures are now covered in the new paragraph 10. All subsequent subparagraphs have been renumbered.

Subparagraph 3.10

Comments. One commenter pointed to an error under subparagraph 3.10 (2.11), "Emergency Action," stating that "* * * reference to subparagraph 2.7 appears to be a typographical error, and it should probably refer to subparagraph 2.1."

Discussion. The suggestion is correct; subparagraph 3.1 (2.1) also should have been referenced. New subparagraph 3.10, "Emergency Action," has been revised to include the phrase "* * * in accordance with the provisions of this Order * * *." Therefore, specific paragraphs are not referenced.

Subparagraph 3.11

Comments. In response to subparagraph 3.11 (2.12), "Records," one commenter stated that "This requires records on subsurface-safety devices to be kept for a period of one year. Records on safety devices should be kept continuously throughout the life of the operation."

Discussion. The subparagraph has been changed to require a minimum record-retention period of 5 years for subsurface-safety devices. The 5-year record-retention period was adopted to be consistent with the American National Standards Institute/American Society of Mechanical Engineers Standard "Quality Assurance and Certification of Safety and Pollution Prevention Equipment Used in Offshore Oil and Gas Operations," OCS–1–1977. This standard has been adopted and is referenced in new subparagraph 2a.

The paragraph "Records," the subparagraph "Field Records," and the subparagraph "Other Records" were combined into one paragraph, "Records."

It was determined that the limited storage space in offshore field offices makes the storage of 5 years of records difficult. The Order was revised to state that records could be moved to the onshore office after 2 years. With this change, there was then no need to differentiate between field records and other records. The paragraph and subparagraphs were edited and combined.

Comments. One commenter addressed subparagraph 3.11d (2.12.1b) as follows: "Proposed Order No. 5, paragraph 2.12.1(b) would require verification of assembly by a qualified person in charge of installing the device and installation date. These downhole safety devices are actually factory assembled; therefore, offshore wireline operators could only verify installation and *not* assembly of such devices."

Discussion. The USGS agrees with this comment; subparagraph 3.11f (2.12.1b) has been revised as follows: "The qualifications of the personnel who directed all installations and removals * * *." The verification of the assembly is assured by the revision of subparagraph 3.11b which requires a record verifying that the assembly was manufactured in accordance with the quality-assurance requirements of ANSI–ASME SPPE–1–1977. The installation and removal dates are required by the new subparagraph 3.11g. A new item "c" has been added to require a record of all configuration modifications.

Comments. Several commenters objected to the requirement for the quarterly failure-analysis reports which were required by subparagraph 3.11 (2.12.2), "Other Records," and subparagraph 3.12 (2.13), "Reports." It was suggested that these reports should be submitted semiannually or annually.

Discussion. The "quarterly failure-analysis reports" requirement has been deleted from both of these subparagraphs. A new paragraph 6, "Failure and Inventory Reporting," has been added to this Order to cover equipment-failure reporting. The intention of the USGS to include the requirements for a failure and inventory reporting system (FIRS) in OCS Order No. 5 was announced in a **Federal Register** Notice, Vol. 43, No. 111, June 8, 1978. A discussion of the USGS rationale for the addition of the new paragraph 6 is given under a separate heading for that paragraph.

Subparagraph 4.1

Comments. Subparagraph 4.1 (3.1), "New Platforms," referenced API RP 14C; it was suggested that the phrase "or subsequent revisions as approved by the Supervisor" immediately follow the reference.

Discussion. The USGS has adopted the following phrase: "or subsequent revisions which the Chief, Conservation Division, has approved for use."

Subparagraph 4.2

Comments. A number of commenters were not in favor of the proposed date of December 1, 1977, for existing platforms to be in compliance with the provisions of API RP 14C, as stated in subparagraph 4.2 (3.2). It was contended that this date was "overly stringent," "exceedingly difficult," and "probably impossible to comply with." It was further contended that "Since the effective date of the National Order has not yet been established, then neither should this effective date of compliance by existing platforms be established."

Discussion. It has been recognized that the effective date for existing production platform facilities to be in compliance with the requirements of this subparagraph must be consistent with the existing Orders for those Areas which have existing production platforms. The currently effective OCS Order No. 8 for the Gulf of Mexico Area requires conformance on new platforms with the provisions of API RP 14C by April 1, 1977 (6 months after the October 1, 1976, effective date of the Order). This OCS Order also required compliance with the requirements of subparagraph 4D, "Additional Safety and Pollution Control Requirements," as follows:

a. Platforms installed after October 1, 1976, shall comply by April 1, 1977.

b. Existing platforms shall comply by October 1, 1977.

Shortly after the issuance of the September 7, 1976, revision of the Gulf of Mexico OCS Order No. 8, it was recognized that the OCS Order did not state the requirements for compliance with API RP 14C on existing platforms. All lessees in the Gulf of Mexico OCS Area were subsequently informed that Conservation division policy would require compliance with these requirements by October 1, 1977.

Subparagraph 4.2, "Existing Platforms," for the Gulf of Mexico Area has been written to require immediate compliance with the provisions of API RP 14C and with the additional requirements of paragraphs 4 and 5 of the Order.

Since the OCS Orders for the other Areas have not previously required compliance with the provisions of API RP 14C or certain specific requirements of paragraph 4 and 5 of OCS Order No. 5, subparagraph 4.2 for the Pacific, Gulf of Alaska, and Atlantic has been written to require compliance by January 1, 1980.

Subparagraph 4.3

Comments. No comments received.

Discussion. A new subparagraph 4.3 was written to incorporate a "grandfather clause" and to specify a date for compliance with "API Specification for Wellhead Surface Safety Valves for Offshore Service," API Spec 14D. This specification was not referenced in the proposed National OCS Orders because the Second Edition of the standard was not finalized and issued until November 1977. Refer to the discussion of

paragraph 2. The subsequent subparagraphs were renumbered.

Subparagraph 4.4

Comments. It was suggested that the following sentence be added to the first paragraph of subparagraph 4.4 (3.4): "The information shall be reviewed for approval by the District Supervisor within 60 days after being submitted.

Discussion. This suggestion was not adopted because the USGS has no control over the number of applications which are received in a certain time period. A time limit could result in an insufficient scrutiny of design proposals, if a large number were to be received in a 60-day period. The USGS plans to continue its policy of handling urgent matters as expeditiously as possible while fully discharging its regulatory responsibilities.

Subparagraph 4.4f

Comments. It was suggested that the word "smoke" be deleted in the first sentence of subpargraph 4.4f (3.4f). The reason for this suggestion is: "Experience has proven that enclosed high-hazard areas can be adequately protected with gas and fire detectors. API RP 14C only requires gas detectors in inadequately ventilated areas. The suggested revision makes it clear that three different types of fire sensors are not needed."

Discussion. The USGS has adopted this suggestion.

Subparagraph 4.4g

Comments. It was suggested that "This requirement is out of place in the proposed Order since 4.1.10 covers only electrical equipment. It appears that it should be added to 3.4 to be in the proper location."

Discussion. The USGS agrees with this comment. The requirement was revised and incorporated into subparagraph 4.4g.

Comments. This subparagraph was objected to by the following comment: "We seriously object to this requirement. It may be reasonable that designs be certified by appropriate registered professional engineers. It is absolutely not necessary for them to supervise installation, however. This should be done by qualified technicians and/or inspectors."

Another commenter suggested that the word "appropriate" should be deleted, because "In some states, registration by a particular engineering discipline is not used."

Discussion. This subparagraph has been rewitten to delete "appropriate" and to not require "supervision" of an installation by registered professional engineers. The revised subparagraph requires certification of the designs by registered professional engineers.

Subparagraph 5.1.1a

Comments. The following sentence was proposed to be added to the first paragraph of subparagraph 5.1.1a (4.1.1a): "All existing platforms are exempt from this requirement." It was stated that "The added sentence exempts older existing platforms from what would be a massive refitting job to meet a code written after they were constructed."

Discussion. The USGS does not agree. Pressure and fired vessels used in the production of oil or gas should be equipped with properly designed and sized pressure-relief valves, regardless of the age of the vessel.

Lessees who operate in the Gulf of Mexico have known since September 7, 1976, that pressure-relief valves shall conform to ASME boiler and pressure-vessel codes, and new platform production facilities should conform to API RP 14C.

The revision of subparagraph 4.2, "Existing Platforms," requires immediate compliance with the requirements of paragraphs 4 and 5 for the Gulf of Mexico and compliance by January 1, 1980, for all other Areas of the OCS. The rationale for the compliance dates is covered in the discussion for subparagraph 4.2. Furthermore, subparagraph 5.1.1e permits the use of existing uncoded pressure vessels, provided thay are hydrostatically pressure tested to 1.5 times their working pressure.

Comments. Another commenter addressed this subparagraph and suggested that the word "minimize" be deleted and the word "prevent" be substituted.

Discussion. This suggestion was adopted.

Comments. Another commenter addressed the following: "Reference to the ASME Boiler and Pressure Vessel Code, July 1, 1974, or subsequent revisions thereto approved by the Supervisor is used in paragraph (a), but 'subsequent revisions' are not listed in paragraphs (b), (c), and (e). We believe they should be for the sake of consistency."

Discussion. This suggestion was adopted by including the "subsequent revisions" phrase into the introductory paragraph of subparagraph 5.1.1. It is intended that this phrase apply to subsequent subparagraphs.

Subparagraph 5.1.1c

Comments. A commenter suggested that the following second sentence of subparagraph 5.1.1c (4.1.1c) be adopted: "The high pressure shut-in sensor shall activate sufficiently below the maximum allowable working pressure to positively insure operation before the relief valve starts relieving." It was contended that "It would be unsafe to set a high pressure alarm sensor to alert for a pressure which exceeds the manufacturer's 'maximum allowable working' pressure."

Discussion. The USGS review of this comment indicated that subparagraphs 5.1.1a and 5.1.1c should be revised to segregate the requirements for relief valves from the requirements for pressure sensors. The requirements of the original subparagraph 4.1.1c pertaining to the sizing and relieving requirements for relief valves have been incorporated into the revised subparagraph 5.1.1a. A clause was added to subparagraph 5.1.1a which requires relief valves to be set no higher than the maximum-allowable working pressure of the vessel.

Subparagraph 5.1.1c was revised to address the requirements for setting the actuation pressures for the high- and low-pressure shut-in sensors. This subparagraph requires that the high-pressure sensor be set sufficiently below the relief-valve set pressure to ensure that the pressure source is shut in before the relief valve starts relieving. This requirement, combined with the requirement of subparagraph 5.1.1a, prescribes the upper limit of the high-pressure sensor to be below the maximum-allowable pressure for the vessel, since the relief valve must be set below this pressure.

Comments. One commenter questioned the use of kilopascals as the accepted metric unit for pressure: "Is kilopascals or Kg/Cm^2 the accepted metric equivalent of psi?"

Discussion. The kilopascal (kPa) is the accepted unit of pressure by International Systems of Units (SI), and this unit has been adopted by the USGS.

Subparagraph 5.1.1d

Comments. A commenter was concerned with the ASME Boiler and Pressure Vessel Codes referenced in subparagraph 5.1.1d (4.1.1e), and the following statement was made: "In summary, it seems all of those could reference the latest revision. * * * Furthermore, if the government absolutely doesn't accept future revisions without subsequent approvals, this concept should be uniformly applied to all codes; *and* the subsequent approvals should be done once at the National USGS Director level, not duplicated repeatedly at each Supervisor level."

Discussion. The USGS does not bestow "blanket" approval on latest revision to any document, from all sources, without first reviewing the document to determine its applicability and suitability to OCS operations. The "subsequent revisions phrase" has been added to the introductory paragraph of subparagraph 5.1.1 in order to make this phrase applicable to the subsequent subparagraphs. All referenced standards are reviewed and approved by the Chief, Conservation Division, for use in all Areas of the OCS.

Comments. It was recommended that the word "installed" be changed to "ordered" in subparagraph 5.1.1d (4.1.1e). It was stated that "After a vessel is ordered, a change in specifications can be very costly and time consuming, especially if the change must be made at the time the vessel is being installed."

Discussion. This change was adopted.

Comments. Another commenter stated that "Consideration should be given to allow the use of small, uncoded pressure vessels when such vessels are fabricated solely, from pipe and factory made pipe fittings which meet the minimum material requirements for other piping and provided such vessels do not have any internal weldments and are hydrostatically tested to at least 1.5 times their working pressure, all as permitted by OPSO Part 192."

Discussion. The intent of the Order is to require that all pressure vessels, regardless of size, installed after the effective date of this Order shall be coded pressure vessels. Subparagraph 5.1.1d allows uncoded pressure vessels to be used on existing installations provided they have been pressure tested to at least 1.5 times their working pressure.

Subparagraph 5.1.2

Comments. It was proposed that the fourth sentence in subparagraph 5.1.2 (4.1.2) be changed to the following: "The high-pressure shut-in sensor shall be set no higher than 10 percent or 400 psi, whichever is greater, above the highest operating pressure of the line; but, in all cases, it shall be set sufficiently below the design working pressure of the well or the gas-lift supply pressure to assure actuation of the surface-safety valve."

It was also suggested that the fifth sentence of 5.1.2 be ended with the phrase "Before the designed working pressure is exceeded."

Discussion. These suggestions were not adopted. If the 400 psi criteria were adopted, then all wells with flowing tubing pressure of 400 psi, or less, would have their sensors set at the flowing pressure plus 400 psi. We believe that in many cases of low-pressure wells, the 400 psi could be excessive, whereas, the 10 percent is believed to be a better overall criteria, and would shut in the wells on signal of a downstream emergency.

The primary function of the high-pressure sensor is to shut in the wells in response to a downstream emergency. The secondary function of the high-pressure sensor is to protect the flowline from pressures in excess of the maximum-allowable working pressure. Therefore, the term "maximum shut-in pressure" was retained.

Comments. Another commenter proposed that "In the last phase of the third sentence the words should read 'below the maximum shut-in wellhead pressure', if *wellhead* pressure is what is intended."

Discussion. This proposal was adopted.

Subparagraph 5.1.3

Comments. No comments received.

Discussion. The original subparagraph 4.1.1d addressed general requirements for pressure sensors. The USGS concluded that these requirements should be covered under a separate heading, instead of including this requirement under the heading of pressure vessels; therefore, the requirements were incorporated into a new subparagraph 5.1.3, "Pressure Sensors."

Comments. A commenter responded to subparagraph 5.1.3 (4.1.1d), stating that "The wording of this requirement which specifies that a 'non-automatic *reset* relay shall be installed' is unduly restrictive in that it precludes certain design options the engineer (operator) may choose for the design on unmanned and automated unattended platforms. For example, a design objective might provide that when the pressure parameters normalize, the facility would automatically resume operations. There is no need to send a service crew by helicopter for shutdowns occassioned by minor self-correcting upsets or deviations."

Discussion. The USGS does not agree. There are also numerous examples of wellhead and platform equipment failures which could contribute to a fire and to pollution, with an automatic reset system.

It is intended that the "shutdown condition" shall remain in effect until the cause of the abnormal condition has been determined and corrected.

Subparagrah 5.1.4

Comments. No comments received.

Discussion. The title of subparagraph 5.1.4 (4.1.3) was changed from "Remote Shut-In Systems" to "Emergency Shutdown (ESD) System." This change was made to be consistent with the terminology of API RP 14C.

Comments. It was suggested that subparagraph 5.1.4 (4.1.3) be changed to allow for the use of a plastic loop of the control-pressure line. This loop may be located at the boat landings of the platform. It was stated that this arrangement would "* * * allow a platform to be shut in without personnel having to board the platform by breaking these plastic loops with boat hooks."

Discussion. In order to be consistent with subparagraphs 4. 1 and 4.2 which require conformance with API RP 14C, the following sentence was added following the first sentence of the subparagraph: "ESD stations may utilize a loop of breakable synthetic tubing in lieu of a valve."

Comments. Several commenters objected to the requirement that the platform shut-in shall be completed within 45 seconds after a shut-in control is activated. It was felt that a 45-second-response time would be unsafe and impractical for very large hydraulic systems.

Discussion. Although special consideration may be justified for very large shut-in systems on new and existing platforms, the USGS believes that a response time of 45 seconds is generally feasible and this response time is sanctioned by API RP 14C, Section C2, Second Edition, January 1978.

Subparagraph 5.1.6

Comments. Several commenters suggested that subparagraph 5.1.6 (4.1.5) should permit glycol-dehydration units to be equipped with a pressure-relief value "or an adequate vent."

Discussion. This suggestion was adopted.

Subparagraph 5.1.7

Comments. It was suggested that in subparagraph 5.1.7a(1) (4.1.6a(1)) the word "on" be changed to "to protect." In support of this, it was noted that "PSV's and PSH's are commonly installed upstream of coolers, not on interstate scrubbers." This change may also be applied to the following subparagraphs of 5.1.7 (4.1.6): a(1), a(2), a(3), b(1), and b(2).

Discussion. The USGS agrees and has adopted the new phrase in the above subparagraphs.

Comments. In a comment on subparagraph 5.1.7a(4) (4.1.6a(4)), one commenter stated that "The word 'building' is subject to interpretation. We suggest that the words 'room' or 'compartment' be substituted for 'building.' In cold weather climates, the entire platform may be totally enclosed and considered one building. The compressors are often located inside enclosures which may be considered as rooms in a building and shutdown devices (SDV's) may be located in a separate adjacent room for added safety."

Discussion. There are compressor stations in buildings on the OCS; however, to allow for exceptions, the term "building, room, or compartment" was adopted.

Comments. It was suggested that the second paragraph of the original subparagraph 4.1.6c be moved to subparagraph 4.1.6b(2) since the paragraph covers the use of level safety low shut-in controls.

Discussion. The suggestion is appropriate and has been moved to become the second sentence of new subparagraph 5.1.7b(2).

Comments. No comments received.

Discussion. The second paragraph of the original subparagraph 4.1.6b(3) was deleted. These requirements are covered by 5.1.7b(4) and the reference to subsection A8.3 of API RP 14C.

Comments. In a comment on subparagraph 5.1.7b(4) (4.1.6c), it was noted that "* * * level safety low shut-in controls * * * should be changed to "level safety *high* shut-in controls.

Discussion. The USGS agrees and has adopted the change. For editorial clarity, the former subparagraph 4.1.6c was renumbered 5.1.7b(4) and the former subparagraph 4.1.6d was renumbered 5.1.7c, and retitled, "Small Compressor Installations."

Former Subparagraph 4.1.7

Comments. The comments received on the original subparagraph 4.1.7 indicated that the requirements for "Curbs, Gutters, and Drains" was misplaced in this Order.

Discussion. The USGS review of the comments on the requirements of the proposed subparagraph 4.1.7, "Curbs, Gutters, and Drains," of the proposed OCS Order No. 5 and the comments received on subparagraph 1.1.4, "Curbs, Gutters, and Drains," of the proposed OCS Order No. 7, indicated that the requirements of these subparagraphs should be addressed only in OCS Order No. 7, "Pollution Prevention and Control." Therefore this paragraph was deleted from OCS Order No. 5 and the requirements were included under subparagraph 1.1.3, "Curbs, Gutters, and Drains for Fixed Platforms or Structures and Mobile Drilling Units." Refer to the discussions for subparagraph 1.1.3 for OCS Order No. 7.

Subparagraph 5.1.8

Comments. "Wording should be changed to be the Gulf of Mexico wording since it is too early to tell if requirements for other Areas need to be different from the Gulf of Mexico. Also, the National Orders should be written for Areas of minimum requirements. If increased requirements are justified in other Areas, then these should be separately identified in an appendix."

Discussion. Since this Order was published in proposed form, the API has completed and published API "Recommended Practice for Fire Prevention and Control on Open Type Offshore Production Platforms," API RP 14G, First Edition, September 1978. Our review has indicated that subsection 5.2, "Fire Water Systems," contains requirements which are applicable to all Areas of the OCS. Therefore, this subparagraph was rewritten to require that installations completed after the effective date of this Order shall conform

with subsection 5.2 and the additional requirements of subparagraph 5.1.8 of OCS Order No. 5. This revision deletes the requirements for an alternate pump, and requires that fuel or power be available for a period of 30 minutes after platform shut in. This provides sufficient time to either control the fire or to take other actions.

Subparagraph 5.1.9

Comments. It was suggested that the first sentence of subparagraph 5.1.9a (4.1.9a) be changed to the following: "Fire (flame, heat, or smoke) sensors * * *." It was stated that "Experience has proven that enclosed high-hazard areas can be adequately protected with gas and fire detectors. API Rp 14C only requires gas detectors in inadequately ventilated areas. The suggested revision make it clear that three different types of fire sensors are not needed."

Discussion. The USGS believes the suggestion has merit and has adopted this recommendation.

Comments. One commenter suggested that "* * * purge and pressurizing techniques as provided in National Electrical Code be included as an alternate to installation of detectors listed in 4.1.9(b)."

Discussion: The USGS does not believe that purge systems may be used as an alternative to fire and gas detection systems; however, a new subparagraph, 5.1.9e, has been added to reference the National Electrical Code.

Comments. A commenter recommended that subparagraph 5.1.9b (4.1.9b) be changed to delete the phrase "in the areas in which the detection devices are located."

Discussion. New subparagraph 5.1.9b has been changed to the following: "All detection systems shall be capable of continuous monitoring. The systems shall be of the manual-reset type."

Comments. Several commenters addressed subparagraph 5.1.9c (4.1.9c), and recommended that "as well as" be changed to "is an acceptable alternate to."

Discussion. It is recognized that odorants have certain disadvantages; however, they can be safely used. It is intended that the odorant act as a backup in the event of a malfunction of the gas-detection system. Considering the consequences of a gas leak, fire, or an explosion, we believe that this redundancy is justified.

Comments. A commenter stated that "Enclosed, continuously manned areas of the facility which do not have any gas handling or using equipment are presumably exempt from the automatic gas detection and alarm system requirements."

Another commenter stated that "The intent of this subparagraph is unclear."

Discussion. Subparagraph 5.1.9a has been changed to define a highly hazardous area. Under the definition, gas-detection equipment would not be required in manned areas where no fuel gas is used.

Subparagraph 5.1.10

Comments. It was suggested that subparagraph 5.1.10a (4.1.10a) be revised as follows: "All engines shall be equipped with a low-tension ignition system designed and maintained to minimize release of sufficient electrical energy to cause ignition of an external combustible material."

Discussion. This subparagraph was not revised. While this proposal would delete the phrase "low-fire-hazard type" from the description of engine ignition systems, the major concern is not with the wording but with the interception by USGS personnel that in order to satisfy this requirement, the ignition systems must be shielded. This interpretation did not originate with the USGS and is consistent with petroleum industry-recommended practices for engines operating in a hazardous area. Paragraph 6.4.5.1 of "Reciprocating Compressors for the General Refinery Services" API Standard 618, Second Edition, July 1974, states: "If a hazardous area is specified, all parts of the ignition system shall be as explosion-proof as possible. The spark plugs shall be shielded, and all low-tension wiring shall be enclosed in grounded steel conduits, but spark plug connecting cables shall be enclosed in grounded, metal-shielded, flexible conduits." The 1964 issue of API Standard 618 described such a system with the phrase "low-fire-hazard type of ignition system."

Additionally, the National Electrical Code and its supporting documents dealing with the hazardous classification of areas defines the area about a hydrocarbon compressor or pump, engine combination, as Class I, Division 1 or 2. This area classification would require the use of an ignition system as defined by paragraph 6.4.5.1 of API Standard 618.

It is our intention that the shielded ignition system requirement and the interpretation of the hardware required to satisfy the requirement remain the same until the ASME committee on "Shielded Ignition System for Industrial Engines" has produced an acceptable industry standard which could be referenced.

Subparagraph 5.1.10b

Comments. It was proposed that the last word in subparagraph 5.1.10b (4.1.10b) be changed from "installation" to "approval."

Discussion. This proposal was adopted.

Subparagraph 5.1.10c

Comments. Another similar suggestion was to change the last word in subparagraph 5.1.9c (4.1.10c) from "installation" to "approval."

Discussion. This proposal was adopted. The subparagraph was rewritten to reference the latest editions of the National Electrical Code and the Institute of Electric and Electronic Engineers (IEEE) Standard 45–1977.

Former subparagraph 4.1.16e

Comments. It was proposed that the sentence be changed to add the following prefix: "For installations made after the effective date of this order."

Discussion. The USGS has reevaluated this requirement and has determined that the statement is too general in meaning. In some installations, it may be desirable to provide lockouts for certain equipment functions. These lockouts would constitute special requirements, dependent upon the complexity of the platform. These special requirements will be considered during the review and approval process of new platform installations. Because of these reasons, this subparagraph has been deleted.

Subparagraph 5.1.10e

Comments. It was recommended that subparagraph 5.1.10e (4.1.10f) be deleted. It was contended that "Posting of such a schematic would serve no useful purpose in enhancing platform safety. Only skilled electrical technicians can interpret and work on such systems, and highly detailed schematics are required for their work."

Discussion. It is intended that the schematic must be elementary, functional, and simple to interpret. It is not intended that the drawing be highly detailed. The subparagraph refers to the "elementary" electrical schematic required by subparagraph 4.3e(2), which requires the schematic to have "a functional legend." The intent of the requirement is that the schematic would indicate "How the electrical safety system functions;" therefore, the following sentence was added to the subparagraph: "This schematic shall indicate the control functions of all electrically actuated safety devices." It is considered desirable and necessary that all crew members become familiar with the platform safety-shutdown system, know the purpose of each electrical control, and know where they are located.

Comments. Another commenter suggested that "The posting of the safety shutdown system schematic should not be limited to electrical, but should include all shutdowns including pneumatic and/or hydraulic."

Discussion. The USGS agrees with this suggestion. Subparagraph 5.1.4, "Emergency Shutdown (ESD) System," was revised to require the posting of a schematic of the ESD system indicating the control functions of *all* safety devices. The pneumatic, hydraulic, and/or electrical controls would be included on this schematic.

Subparagraph 5.1.10f

Comments. It was suggested that "This requirement is out of place in the proposed Order since 4.1.10 covers only electrical equipment. It appears that it should be added to 3.4 to be in the proper location."

Discussion. The USGS agrees with this comment. The first sentence was revised and incorporated into subparagraph 4.3g. The second sentence was retained in subparagraph 5.1.10f. Other comments on the original subparagraph 4.1.10g have been answered in the discussions for the new subparagraph 4.3g.

Subparagraph 5.1.11

Comments. One commenter recommended that the annual report date in subparagraph 5.1.1 (4.1.11) be changed from September to December, noting that most survey work is done in the summer months. "The September 1 reporting date does not allow sufficient time to submit data for the current year."

Another commenter stated that "We feel that this should be changed to say that erosion control shall be in effect for wells or fields having a history of sand production.

New wells in a known sand producing field will not have a history of sand production, but since the field does, the new wells should be protected."

Discussion. These suggestions were adopted. The last sentence was also revised to require that the annual report shall indicate which wells have an erosion-control program in effect.

Subparagraph 5.2

Comments. It was suggested that the second sentence in subparagraph 5.2 (4.2) be reworded as follows: "Subsurface safety devices and systems on wells which are capable of flow shall not be bypassed or blocked out of service, unless necessary during maintenance operations, etc. The comma after necessary must be removed for this sentence to make sense."

Discussion. This sentence was changed to the following: "Safety devices may be pypassed or blocked out of service if they are temporarily out of service due to startup, maintenance, or testing procedures, provided that personnel are monitoring the blocked-out functions."

Subparagraph 5.3

Comments. The consensus on subparagraph 5.3 (4.3), "Simultaneous Platform Operations," was that a "plan" should not be required for each well operation or for each platform. It was recommended that the phrase "for each platform" be deleted. It was contended that "There is no need for a completely separate plan for each platform as evidenced by experience in the Gulf of Mexico. The existing Gulf of Mexico Order 8 does not contain a phrase which is recommended for deletion."

Another commenter stated that "* * * the value of furnishing these plans to the district supervisor is not real clear."

Discussion. The Gulf of Mexico OCS Order No. 8, effective October 1, 1976, does contain the phrase "for each platform." Subparagraph 4D(2)(c), "Simultaneous Operations," is quoted in part: "A plan shall be submitted by each lessee/operator for each platform existing as of the effective date of this Order."

It is considered feasible, however, to delete the phrase "for each platform" and to rewrite the subparagraph which is quoted in part as follows: "* * * a 'General Plan for Conducting Simultaneous Operations' in a producing field shall be filed for approval with the District Supervisor. This plan shall be modified and updated by supplemental plans when actual simultaneous operations are scheduled."

These plans shall be submitted to the District Supervisor as it is not administratively feasible for the USGS to monitor each individual simultaneous operation. Therefore, a general plan detailing all potential simultaneous operations for each field and supplemental plans covering scheduled simultaneous operations should provide an effective method for supervising proposed operations.

The subparagraph includes specific requirements for the designation of one person to be responsible for all operations being conducted on the platform.

Subparagraph 5.4

Comments. A commenter stated that the last part of the third sentence in the first paragraph of subparagraph 5.4 (4.4) should be changed to the following: "* * * are pulled in the final abandonment or suspension of the last well on the platform." It was contended that "Just because the well is completed is not reason for cancelling these welding practices and procedures."

Discussion. The USGS agrees with this comment. The first paragraph of the subparagraph was revised accordingly.

The United States Coast Guard supervises welding practices and procedures on offshore mobile-drilling units which are not in the drilling mode.

Comments. One commenter stated that "We urge that the provisions of 4.4 not apply to mobile drilling vessels." It was contended that "The amount of welding on mobile drilling rigs is minor * * *."

Discussion. The danger is considered equal to mobile- or nonmobile-drilling units when an unexpected high-pressure gas zone is encountered and the mud becomes gas cut. The revision of the subparagraph requires the same precautions, regardless of the type of rig.

Comments. It was proposed that the following requirement be deleted from this subparagraph: "All offshore welding and burning shall be minimized by onshore fabrication when feasible."

Discussion. This statement was not deleted. The intent is to minimize offshore welding. The lessee has the option to determine if it is more feasible to fabricate platform components either onshore or offshore.

Subparagraph 5.4b

Comments. Another commenter suggested that "The Fire Watch should also maintain a continuous surveillance with a gas detector during welding."

Discussion. The USGS considers this an added contribution to safety in welding operations. This suggestion was adopted by adding the following sentence to subparagraph 5.4b (4.4d): "If welding is to be done in an area which is not equipped with a gas detector, the Fire Watch shall also maintain a continuous surveillance with a portable gas detector during welding."

Subparagraph 5.4d

Comments. It was recommended that the first sentence of subparagraph 5.4d (4.4f) should contain the word "piping."

Discussion. The USGS agrees and has adopted this recommendation.

Subparagraph 5.4e

Comments. It was contended in a comment on subparagraph 5.4e (4.4g) that "Some platforms have several wellhead compartments widely separated from one another and welding in one would not provide an ignition source for well operation in the other." It was suggested that the first sentence be reworded as follows: "In the event drilling, workover, or wireline operations are in progress on the platform, welding operations in the well room, compartment or area where these operations are in progress, may be conducted only if the well(s) * * *."

Discussion. Subparagraph 5.4 (4.4), "Welding Practices and Procedures," was written to cover general platform floor plans. This comment is based on wellhead compartments which are widely separated from each other. These conditions would merit consideration for departure.

Subparagraph 5.4f

Comments. It was recommended that subparagraph 5.4f (4.4h) be deleted. It was contended that welding operations can be conducted safely while maintaining production if adequate safety precautions are taken beforehand.

Discussion. This subparagraph was not changed. We believe that all welding or burning operations in the area of the wellhead, well bay, or production areas are potentially hazardous, and we believe the possibility of potential fire and/or explosion should be precluded. Except in emergencies, welding operations should be scheduled when the platform is shut in.

Subparagraph 5.5a

Comments. Several commenters objected to the semiannual testing of pressure relief valves required by subparagraph 5.5a (4.5a). The commenters contended that annual testing has proven satisfactory.

Discussion. This time period has been reconsidered and the annual period has been adopted.

Subparagraph 5.5c

Comments. A number of commenters objected to the requirement in subparagraph 5.5c (4.5c) that all surface-safety valves (SSV's) shall be checked for operation on a "weekly" basis. The consensus was that a "weekly" basis is excessive and a "monthly" basis is sufficient to establish the fact that these valves function properly.

Discussion. The operational testing of these valves on a "weekly" basis has been reconsidered and a "monthly" basis has been adopted.

Comments. Several commenters indicated that the allowable leakage rates for automatic wellhead safety devices and check valves should be different; therefore, these requirements should be segregated into separate paragraphs.

Discussion. The requirements were segregated into separate subparagraphs 5.5c and 5.5d, addressing the testing requirements for testing of surface-safety valves (SSV's) and flow safety valves (FSV's). The terminology of the requirements was revised to be consistent with API AP 14C. All subsequent items under subparagraph 5.5 were relettered.

Comments. Another commenter proposed that a wellhead safety valve leakage allowance be provided, not to exceed 200 cc/min liquid or 10 cfm gas. When these values are exceeded, the valve should be repaired or replaced.

Discussion. The USGS finds no justification to allow wellhead safety valve leaks. If

valves, with the correct sizing, working pressure, and seating arrangement, are selected and correctly installed by the lessee, no leaks should be anticipated. The numerous valve manufacturers do not design and fabricate valves with the intent that some "leakage tolerance" should be allowed. This is consistent with the requirements of paragraph 4 of this Order which prescribe that all wellhead surface-safety valves installed after July 1, 1979, shall conform to API Specification 14D. The performance tests in this specification state that "no leakage shall be allowed."

Subsection 5.5c has been revised to require SSV's to be tested for operation and leakage in accordance with API RP 14C. The subparagraph requires replacement of the valve if any fluid flow is observed in step 3 of the leakage-test procedure.

The USGS recognizes that the purpose of an FSV is to control backflow of fluid and that leakage is not as critical as leakage from an SSV. The SSV is intended to stop all flow from the well. Therefore, a new subparagraph 5.5d has been added which requires FSV's to be tested in accordance with API RP 14C and provides a leakage tolerance of 400 cc/min for liquid flow and 7 dm^3/sec (15 cubic ft/min) for gas flow.

Subparagraph 5.5e

Comments. In a comment on subparagraph 5.5e (4.5d), it was proposed that "An alternate provision should be made for testing such controls on dry vessels or those vessels with limited liquid entry, such as to hand-trip the external switch in order to test its function."

Discussion. This proposal was not adopted because these controls should be tested in normal operating sequences. It is desirable to preclude the possibility of internal malfunction such as a stuck float, etc.

Subparagraph 5.5j (4.5.i)

Comments. It was suggested in a comment on subparagraph 5.5j (4.5i) that "smoke, fire, and gas" be changed to "fire and gas."

Discussion. The term "fire (flame, heat or smoke) and gas" was adopted to be consistent with subparagraph 5.1.9a.

Subparagraph 5.5k

Comments. Another commenter recommended that the second and third sentences in subparagraph 5.5k (4.5j) be deleted. It was stated that "While an initial test and inspection of the integrated safety system would be useful, the repetition of this test and inspection at 6-month intervals serves no useful purpose. Most safety devices are tested monthly and all are tested at least every 6 months. In addition, the USGS report entitled 'Policies, Practices, and Responsibilities for Safety and Environmental Protection in Oil and Gas Operations on the Outer Continental Shelf,' published in June of 1977, indicates that the USGS inspects all major platforms at least semiannually and all minor platforms at least once each 15 months. In addition, scheduling such tests so that they can be witnessed by USGS representatives would result in significant lost production."

Discussion. The USGS has reevaluated the requirement for a complete test and inspection of the integrated safety system every 6 months. The subparagraph has been revised to require pre- and postproduction tests and inspections. These tests, together with the frequency of the testing requirements for the individual components, are considered adequate to assure that the safety system will function properly.

During inspection of the platform by USGS inspectors, the integrated safety system may be tested at any time.

Comments. It was noted that "Offshore operations are both costly and highly weather dependent, and, therefore, any delays to accommodate schedule itineraries of government inspection representatives should be minimized."

Discussion. The revision of the subparagraph, as discussed above, provides for the coordination and scheduling of the tests.

Subparagraph 5.6

Comments. It was suggested in a comment on subparagraph 5.6 (4.5) that the 1-year record-retention period be extended as follows: "to ensure adequate safety devices are being used, continuous records on safety devices at the operations should be kept and must be available."

Discussion. A new subparagraph 5.6, "Records," has been added to be consistent with the recordkeeping requirements for subsurface-safety valves required by subparagraph 3.11 and ANSI/ASME OCS–1–1977. The new subparagraph requires a record-retention period of 5 years. Refer to the discussion for subparagraph 3.11.

Subparagraph 5.6.1

Comments. No comments received.

Discussion. A new subparagraph 5.6.1 has been added to address the quality-assurance recordkeeping requirements of ANSI/ASME–SPPE–1 (formerly ANSI/ASME–OCS–1) for surface-safety valves.

Subparagraph 5.7

Comments. Several commenters objected to the October 1, 1978, date of compliance with the training requirements as stated in subparagraph 5.7 (4.6).

Discussion. In the Gulf of Mexico Area, this requirement was originally in subparagraph 4.D(4) of OCS Order No. 8, which was revised and published in the Federal Register, Vol. 41, No. 174, September 7, 1976. This revision became effective October 1, 1976, and required that personnel be trained by October 1, 1978. Therefore, the Gulf of Mexico OCS Order was revised accordingly. The Orders were revised for all other Areas to allow 1 year for submittal of a training plan and 2 years for the qualification of personnel.

Comments. It was suggested that the fourth paragraph and subparagraphs (a) through (g) be deleted. It was noted that "The fourth paragraph of this section would require that the operator report to the USGS as to how it intends to comply with the first paragraph."

The comments concerning subparagraphs (a) through (g) generally stated that "* * * should not concern the USGS," or other statements with similar meaning.

Discussion. The USGS does not agree with these comments concerning subparagraphs (a) through (g), nor with the suggested deletion of the fourth paragraph. This requirement has been rewritten as follows: "* * * the lessee shall submit an application for approval to the Chief, Conservation Division, describing the training to be conducted and the methods the lessee will utilize." This revision will assure consistency in the training plans of all Areas of the OCS.

The Gulf of Mexico OCS Order No. 8, effective October 1, 1976, required that a plan be submitted for approval within 1 year after the effective date of the Order and training be completed by October 1, 1978. These requirements have not been changed. The requirements of the other Areas have been revised to state the same time limitations for compliance as were given in the Gulf of Mexico OCS Order.

The USGS is concerned that all lessees operating on the OCS properly train their personnel in the installation, inspection, testing, and maintenance of safety devices.

Paragraph 6

Comments. Comments pertaining to the content of this paragraph were received in response to the Federal Register solicitations for comments dated April 12, 1976, and May 13, 1976.

Discussion. A new paragraph 6, "Failure and Inventory Reporting," has been added to this Order. The content of this paragraph was developed after considering comments received pertaining to a "Safety Device Inventory Reporting" system, which was published in the Federal Register, Vol. 41, No. 71, April 12, 1976, and from a solicitation for comments pertaining to a "Safety Device Failure and Activity Reporting System," which was published in the Federal Register, Vol. 41, No. 94, May 13, 1976. Our review of the comments indicated that the requirements for a Safety Device Failure and Inventory Reporting System (FIRS) should be incorporated into an OCS Order, instead of into two separate Notices to Lessees and Operators, as originally proposed.

A Notice was published in the Federal Register, Vol. 43, No. 111, June 8, 1978, which announced our intention to include the FIRS requirements in National OCS Order No. 5. As stated in the preamble of the "Revised Outer Continental Shelf Orders Governing Oil and Gas Lease Operations in All Areas," the Department has determined that it is in the public interest to issue revised Area OCS Orders instead of National OCS Orders at this time. Therefore, the FIRS requirements have been incorporated into paragraph 6 of the revisions of OCS Order No. 5 for all Areas of the OCS. Refer to the Federal Register Notice of June 8, 1978, for a discussion of the comments received and our rationales for the final FIRS requirements.

Paragraph 8

Comments. One commenter stated in a comment on paragraph 8(6) that "* * * the criteria described are excessive in their requirements. 'Instill * * * a conscious desire

to achieve' is a goal that would require extensive training and still be ineffective on many individuals."

Discussion. This paragraph has been rewritten to delete the phrase "* * * to instill in each individual * * *." The following sentence has been added: "A program to achieve safe and pollution-free operations shall be established." It is intended that individuals working offshore be properly trained, and that safe and pollution-free operations be stressed as part of their job responsibilities.

Subparagraph 9.2

Comments. It was proposed in a comment on subparagraph 9.2 (7.2) that new items 7.1f and 7.2c be added which would state that "When the rig is not owned by the operator, the operator shall require the contractor to have a welding practices and procedures plan and personnel training program which meet, as a minimum, the requirements of this Order."

Discussion. The intent of the OCS Orders is to ensure that the lessee is responsible for all operations on the lease. Therefore, the lessee is required to assure compliance with all requirements, regardless of who performs the work.

Comments. No comments received.

Discussion. The original item 7.1a was deleted because the original subparagraph 4.1.7, "Curbs, Gutters, and Drains," was moved to OCS Order No. 7.

A new item 9.1b was added because subparagraph 5.3, "Simultaneous Platform Operations," is applicable to drilling rigs on fixed structures.

The original item 7.1d was deleted because crane operations are a separate requirement and should not be included under the heading of "Requirements for Drilling Rigs."

United States Department of the Interior; Geological Survey Conservation Division

OCS Order No. 5, Effective July 1, 1979; Production safety systems

This Order is issued pursuant to the authority prescribed in 30 CFR 250.11 and 250.12(a), and in accordance with 30 CFR 250.41(b), 250.42, and 250.46. The lessee shall be responsible for compliance with the requirements of this Order in the installation and operation of the production safety systems on all platforms and structures including those facilities not operated or owned by the lessee. All applications for approval under the provisions of this Order shall be submitted to the District Supervisor.

1. *Technological Improvement.* The lessee is encouraged to continue the development of safety-system technology. As research and product improvement result in increased effectiveness of existing safety equipment or the development of new equipment systems, such equipment may be used or required.

2. *Quality Assurance and Performance of Safety and Pollution-Prevention Equipment.* Safety and Pollution-Prevention Equipment (SPPE) shall conform to the following quality assurance standards or subsequent revisions which the Chief, Conservation Division, has approved for use.

a. American National Standards Institute/American Society of Mechanical Engineers Standards "Quality Assurance and Certification of Safety and Pollution Prevention Equipment Used in Offshore Oil and Gas Operations," ANSI/ASME SPPE–1–1977, December 1977 (formerly ANSI/ASME–OCS–1–1977).

b. American National Standards Institute/American Society of Mechanical Engineers Standard "Accreditation of Testing Laboratories for Safety and Pollution Prevention Equipment Used in Offshore Oil and Gas Operations," ANSI/ASME–SPPE–2–1977, December 1977 (formerly ANSI/ASME–OCS–2–1977).

The dates for compliance with these quality assurance standards, the applicable SPPE components, and the applicable SPPE specifications are identified in subparagraph 3.2 and subparagraph 4.3.

3. *Subsurface-Safety Devices.*

3.1 *Installation.* All tubing installations open to hydrocarbon-bearing zones shall be equipped with a subsurface-safety device such as a Surface-Controlled Subsurface-Safety Valve (SCSSV), a Subsurface-Controlled Safety Valve (SSCSV), an injection valve, or a tubing plug, unless, after application and justification, the well is determined to be incapable of flowing. The device shall be installed at a depth of 30 meters (98 feet) or more below the ocean floor within 2 days after production is stabilized. The well shall be attended at the wellhead while open to a hydrocarbon-bearing zone, unless a subsurface-safety device is installed.

3.1.1 *Subsurface-Safety Valves.* The requirements for subsurface-safety valves vary according to when the wells are completed. Alternatives to the following requirements may be approved by the Supervisor when greater reliability or safety can be demonstrated.

a. *Wells completed after the effective date of this Order.*

(1) All tubing installations shall be equipped with a surface-or other remotely controlled subsurface-safety device if the shut-in tubing pressure of the well is 27,600 kPa (4,000 psig) or less.

(2) If the shut-in tubing pressure of the well is greater than 27,600 kPa (4,000 psig), the well shall be equipped with a subsurface-controlled subsurface-safety valve. When the shut-in tubing pressure declines below 27,600 (4,000 psig), a surface-or other remotely controlled subsurface-safety valve shall be installed when the tubing is first removed and reinstalled.

b. *Wells completed prior to the effective date of this Order.*

(1) Wells with shut-in tubing pressure of 27,600 kPa (4,000 psig) or less shall be equipped with a surface-or other remotely controlled subsurface-safety valve. If wells are equipped with a subsurface-controlled subsurface-safety valve on the effective date of this Order, they shall be equipped with a surface-or other remotely controlled subsurface-safety device when the tubing is first removed and reinstalled.

(2) Wells with a shut-in tubing pressure greater than 27,600 kPa (4,000 psig) shall be equipped with a subsurface-controlled subsurface-safety valve. If wells are equipped with a surface-or other remotely controlled subsurface-safety valve on the effective date of this Order, They shall be equipped with a subsurface-controlled subsurface-safety valve when the tubing is first removed and reinstalled. When the shut-in tubing pressure declines below 27,600 kPa (4,000 psig), a surface-or other remotely controlled subsurface-safety valve shall be installed when the tubing is first removed and reinstalled.

3.2 *Specification for Subsurface-Safety Valve.* Surface-controlled and subsurface-controlled subsurface-safety valves required by subparagraphs 3.4 and 3.5 which are installed on new installations or replaced on old installations after July 1, 1979, shall conform to "American Petroleum Institute (API) Specification for Subsurface-Safety Valves," API Spec 14A, Third Edition, November 1978, or subsequent revisions which the Chief, Conservation Division, has approved for use at the time of installation.

3.3 *Design, Installation, and Operation.* After the effective date of this Order, new installations, or replacements of old installations of subsurface-safety valves shall be in accordance with "API Recommended Practice for Design, Installation, and Operation of Subsurface Safety Valve Systems," API RP 14B, First Edition, October 1973, or subsequent revisions which the Chief, Conservation Division, has approved for use.

3.4 *Surface-Controlled Subsurface-Safety Valves.* After the effective date of this Order, all tubing installations open to a hydrocarbon-bearing zone shall be equipped with a surface-controlled subsurface-safety valve, except as specified in subparagraphs 3.1, 3.5, and 3.6. The surface controls may be located on the site or at a remote location.

The lessee shall furnish evidence that the surface-controlled subsurface-safety devices and related equipment are capable of normal operation in those Areas which are subject to subfreezing conditions.

3.4.1 *Testing of Surface-Controlled Subsurface-Safety Valves.* Each surface-controlled, or other remotely controlled, subsurface-safety valve installed in a well shall be tested in accordance with Appendix E of API RP 14B, when installed or reinstalled, at least monthly for the first 3 months, and thereafter at intervals not to exceed 6 months. If the device does not operate properly, it shall be promptly removed, repaired, reinstalled, or replaced, and tested to ensure proper operation.

3.5 *Subsurface-Controlled Subsurface-Safety Valves.* Tubing installations in wells completed from single-well and multiwell satellite caissons or jackets and ocean floor completions may be equipped with a subsurface-controlled subsurface-safety valve in lieu of surface-or other remotely controlled subsurface-safety valves.

3.5.1 *Inspection and Maintenance of Subsurface-Controlled Subsurface-Safety Valves.* Each subsurface-controlled subsurface-safety valve installed in a well

shall be removed, inspected, and repaired or adjusted as necessary and reinstalled at intervals not exceeding:

(1) 6 months for those valves not installed in a landing nipple.

(2) 12 months for those valves installed in a landing nipple.

3.2 *Tubing Plugs in Shut-in Wells.* A tubing plug shall be installed in lieu of, or in addition to, other subsurface-safety devices if a well has been shut in for a period of 6 months. Tubing plugs shall be set at a depth of 30 meters (98 feet) or more below the ocean floor. All retrievable plugs installed after the date of this Order shall be of the pump-through type. All wells perforated and completed but not placed on production shall be equipped with a subsurface-safety valve or tubing plug within 2 days after completion. A surface-controlled subsurface-safety valve of the pump-through type may be used as a pump-through tubing plug for the purpose of this subparagraph, provided the surface control has been rendered inoperative. A shut-in well which is equipped with a tubing plug shall be inspected for leakage by opening the well to possible flow at intervals not exceeding 6 months. If a liquid leakage rate in excess of 400 cc/min or a gas leakage rate in excess of 7 dm^3/sec (15 cubic ft/min) is observed, the plug shall be removed, repaired, and reinstalled, or an additional tubing plug may be installed in lieu of removal and repair.

3.7 *Injection Wells.* A surface-controlled subsurface-safety valve or an injection valve capable of preventing backflow shall be installed in all wells placed in injection service after the effective date of this Order.

Wells which were placed in injection service prior to the effective date of this Order shall be equipped ith a surface-controlled subsurface-safety valve or injection valve capable of preventing backflow when the tubing is first removed and reinstalled.

This requirement is not applicable if the District Supervisor concurs that the well is incapable of flowing. The lessee shall verify the no-flow condition of the well annually and submit an annual report certifying the no-flow status of the well.

3.8 *Temporary Removal for Routine Operations.* Each wireling- or pumpdown-retrievable subsurface-safety device may be removed, without further authorization or notice, for a routine operation which does not require the approval of a Sundry Notice and Report on Wells (Form 9–331), for a period not to exceed 15 days. The well shall be identified by a sign on the wellhead stating that the subsurface-safety device has been removed. The removal of the subsurface-safety device shall be noted in the records as required by subparagraph 3.11g. The well shall be attended at the wellhead until the subsurface-safety device has been reinstalled, unless attendance has been waived by the District Supervisor.

3.9 *Additional Safety Equipment.* All tubing installations in which a wireline- or pumpdown-retrievable subsurface-safety device is installed after the effective date of this order shall be equipped with a landing nipple, flow couplings to prevent internal abrasion, or other protective equipment, above and below, to provide for the setting of the subsurface-safety valve. The control system for all surface-controlled subsurface-safety valves shall be an integral part of the platform Emergency Shutdown System (ESD) as defined in API RP 14C, Appendix C, Section C1. In addition to the activation of the ESD system by manual action on the platform, the system may be activated by a signal from a remote location. Surface-controlled subsurface-safety valves shall close in response to shut-in signals from the ESD system or the fire loop, or both.

3.10 *Emergency Action.* All tubing installations open to hydrocarbon-bearing zones in which the subsurface-safety device has been removed, in accordance with the provisions of this Order, shall be identified by a sign on the wellhead stating the subsurface-safety device has been removed. A subsurface-safety device shall be available for each well on the platform. In the event of an emergency such as an impending storm, this device shall be properly installed as soon as possible with due consideration being given to personnel safety.

3.11 *Records.* The lessee shall maintain records for a minimum period of 5 years for each subsurface-safety device installed. These records shall be maintained in the nearest offshore field office for a minimum period of 2 years. The records may then be transferred to the onshore field office for the remaining 3 years of the 5-year retention period. These records shall be available for review by any authorized representative of the U.S. Geological Survey (USGS)., The records to be maintained shall contain verification of:

a. The design, including make, model, and type. For subsurface-controlled valves, number of the spacers, size of beans, springs, and the pressure settings.

b. The devices having been manufactured in accordance with the quality-assurance requirements of ANSI/ASME–SPPE–1 (formerly ANSI/ASME–OCS–1) as required by paragraph 2.

c. The completion and return of the receiving report to the manufacturer as required by ANSI/ASME–SPPE–1.

d. The record of all configuration modifications to the certified design.

e. Installation at the required setting depth and in accordance with the manufacturer's instructions and API RP 14B.

f. The qualifications of the personnel who directed all installations and removals.

g. The results of tests required by this Order, the dates of removals and reinstallations, and the reasons for removals and reinstallations.

h. The completion and submission of all failure reports required by paragraph 6 and all investigation reports required by paragraphs OE–2529 and OE–2670 and ANSI/ASME–SPPE–1.

3.12 *Reports.* Well completion reports (Form 9.330) and any subsequent reports of workover (Form 9.331) shall include the type and the depth of the subsurface-safety devices.

4. *Design, Installation, and Operation of Surface Production Safety Systems.* All production facilities, including separators, treaters, compressors, headers, and flowlines, shall be designed, installed, and maintained in a manner which will facilitate an efficient, safe, and pollution-free operation.

The lessee shall furnish evidence that the surface-safety systems and related equipment are capable of normal operation in those Areas which are subject to subfreezing conditions, and that all equipment and operating procedures take into account floating ice and other extreme environmental conditions that may occur in the Area.

4.1 *New platforms.* New platform production facilities shall be protected with a basic and ancillary surface-safety system designed, analyzed, tested, and maintained in operating condition in accordance with the provisions of "API Recommended Practice for Analysis, Design, Installation, and Testing of Basic Surface Safety Systems on Offshore Production Platforms," API RP 14C, Second Edition, January 1978, except Section A9, "Pipelines," which will be covered under OCS Order No. 9, or subsequent revisions which the Chief, Conservation Division, has approved for use and the additional requirements of the Order. For this application, the word "should" contained in API RP 14C shall be read "shall," except for those contained in explanatory statements, sections 3.4c and 4.3a(4) (a)–(f). If processing components are to be utilized, other than those for which Safety Analysis Checklists (SAC's) are included in API RP 14C, the analysis technique and documentation specified therein shall be utilized to determine the effects and requirements of these components upon the safety system.

4.2 *Existing Platforms.*

Gulf of Mexico

Existing platforms shall comply with the provisions of API RP 14C, except Section A9, "Pipelines," which will be covered under OCS Order No. 9, with the additional safety and pollution-control requirements of paragraphs 4 and 5 of this Order. The submittal of information relative to design and installation features, as listed in subparagraph 4.4, is not required until an equipment modification to an existing facility is performed (other than those necessary for proper maintenance of the facility).

Pacific, Gulf of Alaska, and Atlantic

Existing platforms shall comply with the provisions of API RP 14C, except Section A9, "Pipelines," which will be covered under OCS Order No. 9, with the additionals safety and pollution-control requirements of paragraphs 4 and 5 of this Order, by January 1, 1980. The submittal of information relative to design and installation features, as listed in subparagraph 4.4, is not required until an equipment modification to an existing facility is performed (other than those necessary for proper maintenance of the facility).

4.3 *Specification for Wellhead Surface-Safety Valves.* All wellhead Surface-Safety Valves (SSV's) required by subparagraphs 4.1 and 4.2, which are installed on new installations or replaced on old installations after July 1, 1979, shall conform to "API

Specification for Wellhead Surface Safety Valves for Offshore Service," API Spec 14D, Second Edition, November 1977, as amended by Supplement 1, March 1978, or subsequent revisions which the Chief, Conservation Division, has approved for use at the time of installation.

4.4 *Submittal of Safety-System Design and Installation Features.* Prior to installation, the lessee shall submit for approval to the District Supervisor, in duplicate, information relative to design and installation features, as indicated in subparagraphs a through g. This information shall also be maintained at the lessee's onshore field engineering office. All approvals are subject to field verifications. This information shall include:

a. A schematic flow diagram showing size, capacity, and design working pressure of separators, treaters, storage tanks, compressors, pipeline pumps, and metering devices.

b. A schematic flow diagram (reference API RP 14C, example: figure E1) and the related Safety Analysis Function Evaluation (SAFE) chart (reference API RP 14C, Subsection 4.3c). These diagrams and charts shall be developed in accordance with the provisions of API RP 14C and the additional requirements of this Order.

c. A schematic piping diagram showing the size and design pressure with reference to welding specification(s) or code(s) used. The maximum-allowable working pressures shall be determined in accordance with "API Recommended Practice for Design and Installation of Offshore Production Platform Piping Systems," API RP 14E, First Edition, August 1975, and Supplement 2, October 1977, or subsequent revisions which the Chief, Conservation Division, has approved for use. The recommendations contained in API RP 14E are acceptable for the design and installation of the platform piping system.

d. A diagram of the fire-fighting system.

e. Electrical system information including the following:

(1) A plan of each platform deck outlining any nonrestricted area, i.e., areas which are unclassified with respect to electrical equipment installations and outlining areas in which potential ignition sources, other than electircial, are to be installed. The area outline shall include the following information:

(a) Any surrounding production or other hydrocarbon source and a description of the deck, overhead, and firewall.

(b) Location of generators, control rooms, panel boards, major cabling or conduit routes, and identification of the wiring method, including the identification of each wire and cable type that is utilized.

(2) Elementary electrical schematic of any platform safety-shutdown system with a functional legend.

(3) Classification of areas for electrical installations in accordance with the National Electrical Code, 1978 Edition, and with the "API Recommended Practice for Classification of Areas for Electrical Installations at Drilling Rigs and Production Facilities on lands and on marine Fixed and Mobile Platforms," API RP 500B, Second Edition, July 1973, or subsequent revisions which the Chief, conservation division, has approved for use.

f. The design and schematics of the installation and maintenance of all fire and gas detection systems shall include the following:

(1) Type, location, and number of detection heads.

(2) Type and kind of alarm, including emergency equipment to be activated.

(3) Method used for detection.

(4) Method and frequency of calibration.

(5) Name of organization to perform system inspection and calibration.

(6) A functional block diagram of the detection system, including the electric power supply.

g. Certification that the design for the mechanical and electrical systems were approved by registered professional engineers. After these systems are installed, the lessee shall submit a statement to the District Supervisor certifying that the complete installations conform to the approved designs or the lessee shall request approval of the "As-Built" changes.

5. *Additional Safety and Pollution-Control Requirements.* The following requirements modify or are in addition to those contained in API RP 14C.

5.1 *Design, Installation, and Operation.*

5.1.1 *Pressure Vessels.* Pressure vessels shall be designed, fabricated, stamped, and maintained in accordance with specific sections of the ASME Boiler and Pressure Vessel Code as listed below. The pressure vessels shall conform to the July 1, 1977, edition of the Code or subsequent revisions which the Chief, Conservation Division, has approved for use.

a. Pressure relief valves shall be designed, installed, and maintained in accordance with applicable provisions of sections I, IV, and VIII. The relief valves shall conform to the valve-sizing and pressure-relieving requirements specified in these documents; however, the relief valves shall be set no higher than the maximum-allowable working pressure of the vessel. All relief valves and vents shall be piped in such a way as to prevent fluid form striking personnel or ignition sources.

b. Steam generators shall be equipped with low-water-level controls in accordance with applicable provisions of sections I and IV.

c. The lessee shall determine and record the operating pressure ranges of all pressure-operated vessels in order to establish the pressure-sensor settings. The high-pressure shut-in sensor shall be set no higher than 10 percent above the highest operating pressure of the vessel. This setting shall also be sufficiently below the relief valve's set pressure to assure that the pressure source is shut in before the relief valve starts relieving. The low-pressure shut-in sensor shall activate no lower than 15 percent or 35 kilopascals (kPa) (5 psi), whichever is greater, below the lowest pressure in the operating range.

d. All pressure or fired vessels used in the production of oil or gas, ordered after the effect date of this Order, shall conform to the requirements stipulated in the edition of the ASME Boiler and Pressure Vessel Code, section I, IV, and VIII, as appropriate, in effect at the time the vessel is ordered. Uncoded vessels now in use shall have been hydrostatically tested to a pressure 1.5 times their work pressures.

The test date, test pressure, and working pressure shall be marked on the vessel in a prominent place. A record of the test shall be maintained by the lessee in the field area.

5.1.2 *Flowlines.*—a. All flowlines from wells shall be equipped with high- and low-pressure shut-in sensors located downstream of a well choke. All pressure sensors shall be equipped to permit testing with an external pressure source. The lessee shall determine and record the operating pressure ranges in order to establish pressure-sensor settings. The high-pressure shut-in sensor shall be set no higher than 10 percent above the highest operating pressure of the line; but, in all cases, it shall be set sufficiently below the maximum shut-in wellhead pressure or the gas-lift supply pressure to assure actuation of the surface-safety valve. The low-pressure shut-in sensor shall be set no lower than 10 percent or 35 kPa (5 psi), whichever is greater, below the lowest operating pressure of the line in which it is installed.

b. If a well flows directly to the pipeline before separation, the flowline and valves from the well located upstream of, and including, the header inlet valve(s) shall be able to withstand the maximum shut-in pressure of the well, unless the flowline is protected by one of the following:

(1) A relief valve which vents into the platform flare scrubber of some other location approved by the District Supervisor.

(2) A additional automatic shutdown valve controlled by an independent high-pressure sensor. The platform flare scrubber shall be designed to handle, without liquid-hydrocarbon carryover to the flare, the maximum-anticipated flow of liquid-hydrocarbons which may be relieved to the vessel.

5.1.3 *Pressure Sensors.* Pressure sensors may be of the automatic- or nonautomatic-reset type. When the automatic-reset types are used, a nonautomatic-reset relay shall be installed. All pressure sensors shall be equipped to permit testing with an external pressure source.

5.1.4 *Emergency Shutdown System.* The manually operated ESD valve shall be quick-opening and nonrestricted to enable the rapid actuation of the shutdown system. ESD stations may utilize a loop of breakable synthetic tubing in lieu of a valve. The time for the safety system to effect platform shutdown shall not exceed 45 seconds after the automatic detection of an abnormal condition or the actuation of an ESD station. A schematic of the ESD system shall be posted at a prominent location on the platform. This schematic shall indicate the control functions of all safety devices.

5.1.5 *Engine Exhausts.* Engine exhausts shall be equipped to comply with the insulation and personnel-protection requirements of API RP 14C, Section 4.2c(4). Exhaust piping from internal-combustion engines shall be equipped with spark arrestors.

5.1.6 *Glycol-Dehydration Units.* A pressure relief systems or an adequate vent shall be installed on the glycol regenerator, or at a location approved by the District Supervisor, which will prevent overpressurization of all glycol-dehydration units. The set pressure of the pressure-relief system shall be determined by the lessee and approved by the District Supervisor. The discharge of the relief valve must be vented in a nonhazardous manner. The glycol-dehydration unit shall be properly maintained to prevent overpressurization of the unit.

5.1.7 *Gas Compressors.* a. *Existing Compressor Installations.* Each compressor installation existing as of the effective date of this Order shall be equipped with the following protective equipment:

(1) a Level Safety High (LSH) and a Pressure Safety Valve (PSV) to protect each interstage scrubber.

(2) A Pressure Safety High (PSH) and a Pressure Safety Low (PSL) to protect each interstage scrubber, unless protected by a Temperature Safety High (TSH) shutdown control on the compressor cylinders.

(3) A Level Safety Low (LSL) to protect each interstafe scrubber, unless fluid dump is through a choke restriction to another pressure vessel.

(4) Compressor installations which are installed in a building, room, or compartment are excluded from the requirements of API RP 14C, Subsection A8.3b, "Flow Safety Devices (FSV)," and Subsection A8.3d, "Shutdown Devices (SDV)," which requires that these devices be located outside of the building.

b. *New Compressor Installations.* Each compressor installed after the effective date of this Order shall be equipped with the following protective equipment:

(1) A PSH, a PSL, a PSV, and an LSH to protect each interstage scrubber.

(2) An LSL to protect each interstage scrubber, unless the fluid is dumped through a choke restriction to another pressure vessel. An LSL shut-in control(s) installed in interstage scrubber(s) may be designed to actuate the automatic Shutdown Valve(s) (SDV's) installed in the scrubber dump line(s).

(3) A TSH on each compressor cylinder or other components as applicable.

(4) In addition to the provisions of API RP 14C, Subsection A8.3, PSH and PSL shut-in sensors and LSH shut-in controls protecting compressor suction and interstage scrubbers shall be designed to actuate automatic SDV's located in each compressor suction and fuel gas line so that the compressor unit and the associated vessels can be isolated from all input sources.

All automatic SDV's installed in compressor suction and fuel gas piping shall also be actuated by the shutdown of the prime mover.

c. *Small Compressor Installations.* Compressor installations of 745 kilowatts (1,000 horsepower) or less are excluded from those requirements of API RP 14C, A8, 3d, which provide for installation of a blowdown valve (BDV) on the discharge line.

5.1.8 *Firefighting Systems.* Firefighting systems installed after the effective date of this Order shall conform to Subsection 5.2, "Fire Water Systems," of "API Recommended Practice for Fire Prevention and Control on Open Type Offshore Production Platforms," API RP 14G, First Edition, September 1976, or to subsequent revisions which the Chief, Conservation Division, has approved for use and to the additional requirements of this subparagraph.

A firewater system consisting of rigid pipe with firehose stations shall be installed. A fixed water-spray system shall be installed in the well bays. The system shall be installed to provide needed protection at all times in all areas where production-handling equipment is located.

Acceptable pump drivers include diesel engines, natural gas engines, and electric motors. Fuel or power shall be available for at least 30 minutes of run-time during platform shut-in time. If necessary, an alternate fuel supply shall be installed to provide for this pump-operating time.

A firefighting system using chemicals may be used or may be required in lieu of a water-spray system if the District Supervisor determines that the use of a chemical system provides equivalent fireprotection control. A diagram of the firefighting system showing the location of all firefighting equipment shall be posted in a prominent place on the platform or structure.

Existing firefighting systems shall be reworked to conform to these requirements on or before July 1, 1980.

5.1.9 *Fire and Gas Detection System.* a. Fire (flame, heat, or smoke) sensors shall be used in all enclosed high-hazard areas. Gas sensors shall be used in all inadequately ventilated, enclosed, high-hazard areas. A high-hazard area is defined as:

(1) Any enclosed area containing a gas source, except a meter house with adequate ventillation.

(2) A compressor building.

(3) Any nonsealed enclosed area within 25 feet of a producing well or service area of a producing well, unless the enclosed area does not contain an ignition source. A diagram of the detection system showing the location of all detection points shall be posted in a prominent place on the platform or structure.

b. All detection systems shall be capable of continuous monitoring. The systems shall be of the manual-reset type.

C. A fuel gas odorant and an automatic gas-detection and alarm system are required in enclosed, continuously manned areas of the facility.

d. The District Supervisor may require a gas detector or alarm in any potentially hazardaous area.

e. Fire and gas detection systems shall be of a type as defined in the National Electrical Code, 1978 Edition, or subsequent revisions which the Chief, Conservation Division, has approved for use.

5.1.10 *Electrical Equipment.* The following requirements shall be applicable to all electrical equipment and systems:

a. All engines with ignition systems shall be equipped with a low-tension ignition system of a low-fire-hazard type and shall be designed and maintained to minimize the release of sufficient electrical energy to cause ignition of an external, combustible mixture.

b. All electrical generators, motors, and lighting systems shall be installed, protected, and maintained in accordance with the edition of the National Electrical Code and API RP 500B in effect at the time of approval.

c. At the time of approval, wiring methods shall conform to the National Electrical Code, 1978 Edition, or to the Institute of Electrical and Electronic Engineers (IEEE) "Recommended Practice for Electric Installation on Shipboard," IEEE Std. 45–1977, or subsequent revisions which the Chief, Conservation Division, has approved for use. Each conductor of a wire, a cable, or a bus bar shall be made of copper on all new installations constructed after the effective date of this Order.

d. An auxiliary power supply shall be installed to provide emergency power, capable of operating all electrical equipment required to maintain safety of operations, in the event of a failure in the primary electrical power supply.

e. The elementary electrical schematic of the platform safety-shutdown system required by subparagraph 4.3e(2) shall be posted in a prominent place on the platform or structure. This schematic shall indicate the control functions of all electrically actuated safety devices.

f. Maintenance of these systems shall be by qualified personnel.

5.1.11 *Erosion.* A program of erosion control shall be in effect for wells or fields having a history of sand production. The erosion-control program may include sand probes, X-ray, ultrasonic, or other satisfactory monitoring methods. An annual report, by lease, indicating the wells which have erosion-control programs in effect and the results of the programs shall be submitted by the first of December to the appropriate District Supervisor.

5.2 *General Platform Operations.* a. Safety devices and safety systems on wells which are capable of producing shall not be bypassed or blocked out of service. Safety devices may be bypassed or blocked out of service if they are temporialy out of service due to startup, maintenance, or testing procedures, provided that personnel are monitoring the blocked-out functions. Any device on wells, vessels, or flowlines which is temporialy out of service shall be flagged.

b. When wells are disconnected from producing facilities and blind-flanged or equipped with a tubing plug, compliance is not required with the provisions of API RP 14C or this Order concerning:

(1) Installation of automatic fail-close SSV on wellhead assemblies.

(2) Installation of the PSH and the PSL shut-in sensors downstream of the choke in flowlines from wells.

(3) Installation of flow safety valves (FSV's) in header individual flowlines.

c. All open-ended lines connected to producing facilities shall be plugged or blind-flanged, except those lines designed to be open-ended, such as flare or vent lines.

5.3 *Simultaneous Platform Operations.* Prior to conducting activities simultaneously with production operations which could

increase the possibility of occurrence of undesirable events, such as harm to personnel or to the environment or damage to equipment, a "General Plan for Conducting Simultaneous Operations" in a producing field shall be filed for approval with the District Supervisor. This plan shall be modified and updated by supplemental plans when actual simultaneous operations are scheduled. Activities requiring these plans are drilling, completion, workover, wireline, pumpdown, and major construction operations.

The "General Plan for Conducting Simultaneous Operations" shall include:

a. A narrative description of operations.

b. Procedures for the mitigation of potentially undesirable events including:

(1) The guidelines the lessee will follow to assure coordination and control of simultaneous activities.

(2) An indication of the person having overall responsibility at the site for the safety of platform operations.

The "Supplemental Plan for Conducting Simultaneous Operations" shall include:

a. A floor plan of each platform deck indicating critical areas of simultaneous activities.

b. An outline of any additional safety measures that are required for simultaneous operations.

c. Specification of any added or special equipment or procedural conditions imposed when simultaneous activities are in progress.

5.4 *Welding Practices and Procedures.* The following requirements are applicable to any welding practice or procedure performed on:

a. An offshore mobile-drilling unit during the drilling mode.

b. A mobile workover unit during any drilling, completion, recompletion, remedial, repair, stimulation, or other workover activity.

c. A platform, structure, artificial island, or other installation during any drilling, completion, workover, or production operation.

d. A platform, structure, artificial island, or other installation which contains a well open to a hydrocarbon-bearing zone.

For the purpose of this Order, the terms "welding" and "burning" are defined to include arc or acetylene cutting and arc or acetylene welding.

Each lessee shall file, for approval by the District Supervisor, a "Welding and Burning Safe Practices and Procedures Plan." The plan shall be filed within 90 days after the effective date of this Order and shall include the qualification standards or requirements for personnel and the methods by which the lessee will assure that only personnel meeting such standards or requirements are utilized. A copy of this plan shall be available in the field area. Any person designated as a welding supervisor shall be thoroughly familiar with this plan.

Prior to welding or burning operations, the lessee shall establish approved safe-welding areas. These areas shall be constructed of noncombustible or fire-resistant materials, be free of combustible or flammable contends, and be suitably segregated from adjacent areas. National Fire Protection Association Bulletin "Cutting and Welding Processes," No. 51B, 1971, or subsequent revisions which the Chief, Conservation Division, has approved for use, shall be used as a guide to designate these areas. A drawing showing the location of these areas shall be posted in a prominent place on the facility. All offshore welding and burning shall be minimized by onshore fabrication when feasible.

All welding equipment shall be inspected prior to beginning any welding or burning. Welding machines located on production or process platforms shall be equipped with spark arrestors and drip pans. Welding leads shall be completely insulated and in good condition; oxygen and acetylene bottles secured in a safe place; and hoses leak-free and equipped with proper fittings, gauges, and regulators.

All welding which cannot be done in the approved safe-welding area shall be performed in compliance with the procedures outlined below:

a. Prior to the commencement of any welding or burning operation on a structure, the lessee's designated person-in-charge at the installation shall personally inspect the qualifications of the welder or welders to assure that they are properly qualified in accordance with the lessee-approved qualification standards or requirements for welders. The designated person-in-charge and the welders shall personally inspect the work area for potential fire and explosion hazards. After it has been determined that it is safe to proceed with the welding or burning operation, the designated person-in-charge shall issue a written authorization for the work.

b. During all welding and burning operations, one or more persons shall be designated as a Fire Watch. Persons assigned as a Fire Watch shall have no other duties while actual welding or burning operations are in progress. The Fire Watch shall not be a member of the welding crew. If welding is to be done in an area which is not equipped with a gas detector, the Fire Watch shall also maintain a continuous surveillance with a portable gas detector during welding.

c. Prior to any welding or burning operation, the Fire Watch shall have in his possession firefighting equipment in a usable condition. At the end of the welding operation, the equipement shall be returned to a usable condition.

d. No welding shall be done on piping, containers, tanks, or other vessels which have contained a flammable substance unless the contents have been rendered and determined to be safe for welding or burning by the designated person-in-charge.

e. If drilling, workover, or wireline operations are in progress on the platform, welding operations in other than approved safe-welding areas shall not be conducted unless the well(s) where these operations are in progress contain noncombustible fluids and the entry of formation hydrocarbons into the wellbore is precluded. All other provisions of this section shall also be applicable.

f. If welding or burning operations are conducted on wells or in the well-bay area, all producing wells shall be shut in at the surface-safety valve.

5.5 *Safety Device Testing.* The safety-system devices which are required by this Order shall be tested by the lessee at the interval specified below or more frequently if operating conditions warrant.

Testing shall be in accordance with API RP 14C, appendix D, and the following:

a. All PSV's shall be tested for operation at least annually. These valves shall be either bench-tested or equipped to permit testing with an external pressure source.

b. All Pressure Sensors-High/Low (PSHL) shall be tested at least once each calendar month, but at no time shall more than 6 weeks elapse between tests.

c. All SSV's shall be tested for operation and for leakage at least once each calendar month, but at no time shall more than 6 weeks elapse between tests. The SSV's shall be tested for operation in accordance with the test procedure specified in API RP 14C, appendix D, section D4, table D2, subsection L, and tested for leakage in accordance with subsection M. If the valve does not operate properly or any fluid flow is observed in step 3 of the leakage test, the valve shall be repaired or replaced.

d. All flowline FSV's shall be checked for leakage at least once each calendar month, but at no time shall more than 6 weeks elapse between tests. The FSV's shall be tested for leakage in accordance with the test procedures specified in API RP 14C, appendix D, section D4, table D2, subsection D. If the leakage measured in step 6 exceeds a liquid flow of 400 cm/min or a gas flow of 7 dm^3/sec (15 cubic ft/min), the FSV's shall be repaired or replaced.

e. All LSH and LSL controls shall be tested at least once each calendar month, but at no time shall more than 6 weeks elapse between tests. These tests shall be conducted by raising and lowering the liquid level across the level-control detector.

f. All automatic inlet SDV's which are actuated by a sensor on a vessel or a compressor shall be tested for operation at least once each calendar month, but at no time shall more than 6 weeks elapse between tests.

g. All SDV's located in liquid-discharge lines and actuated by vessel low-level sensors shall be tested for operation once each calendar month, but at no time shall more than 6 weeks elapse between tests.

h. The TSH shutdown controls installed in all compressors which are protected against abnormal pressures solely by temperature safety devices shall be tested semiannually and repaired or replaced as necessary.

i. All pumps for firefighting water systems shall be inspected and test-operated weekly.

j. All fire (flame, heat, or smoke) and gas detection systems shall be tested for operation and recalibrated semiannually, if necessary.

k. The lessee shall notify the District Supervisor when the lessee is ready to conduct a preproduction test and inspection of the integrated safety system. The lessee shall also notify the District Supervisor upon commencement of production in order that a

post-production test and inspection of the integrated system may be conducted.

l. All other safety devices shall be tested annually and repaired or replaced as necessary.

5.6 *Records.* The lessee shall maintain records for a minimum period of 5 years for each surface-safety device installed. These records shall be maintained in the nearest offshore field office for a minimum period of 2 years. The records may then be transferred to the onshore field office for the remaining 3 years of the 5-year retention period. These records shall be available for review by any authorized representative of the U.S. Geological Survey (USGS). The records shall show the present status and history of each device, including dates and details of installation, inspection, testing, repairing, adjustments, and reinstallation. The records shall also include all failure and inventory reports required by paragraph 6 of this Order.

5.6.1 *Surface-Safety Valve and Associated Actuator Records.* Records for surface-safety valves and associated actuators which require compliance with paragraph 2 shall contain additional information showing verification of:

a. The devices having been manufactured in accordance with the quality assurance requirements of ANSI/ASME–SPPE–1 (formerly ANSI/ASME–OCS–1) as required by paragraph 2.

b. The completion and return of the receiving report to the manufacturer as required by ANSI/ASME–SPPE–1.

c. The completion and submission of all failure reports required by paragraph 6 and all investigation reports required by paragraphs OE–2529 and OE–2670 of ANSI/ASME–SPPE–1.

5.7 *Safety Device Training.*

Gulf of Mexico

Personnel engaged in installing, inspecting, testing, and maintaining these safety devices are required to be qualified under a program as recommended by "API Recommended Practice for Qualification Programs for Offshore Production Personnel Who Work With Anti-Pollution Safety Devices," API RP T–2, revised October 1975, or subsequent revisions which the Chief, Conservation Division, has approved for use.

Documented evidence of the qualifications of individuals performing these functions shall be maintained in the field area.

Manufacturers' representatives need not be qualified in accordance with API RP T–2 if they are working on equipment supplied by their company and if they are directly supervised by a qualified person who is capable of evaluating the impact of the work on the total system.

On-the-job trainees working with safety devices shall be directly supervised by a qualified person.

Pacific, Gulf of Alaska, and Atlantic

Before July 1, 1981, the lessee shall ensure that all personnel engaged in installing, inspecting, testing, and maintaining these safety devices will have been qualified under a program as recommended by "API Recommended Practice for Qualification Programs for Offshore Production Personnel Who Work With Anti-Pollution Safety Devices," API RP T–2, revised October 1975, or subsequent revisions which the Chief, Conservation Division, has approved for use.

Documented evidence of the qualifications of individuals performing these functions shall be maintained in the field area.

Manufacturers' representatives need not be qualified in accordance with API RP T–2 if they are working on equipment supplied by their company and if they are directly supervised by a qualified person who is capable of evaluating the impact of the work on the total system.

On-the-job trainees working with safety devices shall be directly supervised by a qualified person.

Before July 1, 1980, the lessee shall submit an application for approval to the Chief, Conservation Division, describing the training to be conducted and the methods the lessee will utilize. The application shall include:

a. A designation of the lessee's representative who is responsible for training and coordinating training matters with the USGS.

b. The categories of personnel to be qualified.

c. The training organizations and courses to be utilized.

d. The method for ensuring the qualification of third-party personnel.

e. The method for determining when additional training or requalification is required and the method for obtaining this training and requalification.

f. The method of monitoring operations to ensure that only qualified personnel perform certain functions.

g. The method of maintaining documented evidence of qualification at the work site.

6. *Failure and Inventory Reporting System (FIRS).* The USGS has established a safety and pollution-prevention device Failure and Inventory Reporting System (FIRS) to enhance the reliability and safety of operations in the OCS. This system applies to offshore structures, including satellites and jackets, which produce or process hydrocarbons and includes the attendant portions of hydrocarbon pipelines, when physically located on the structure.

When the devices specified herein are used as a part of the production-safety and pollution-prevention system, the lessee shall:

a. Submit an initial inventory and periodic updates in accordance with the procedures described in subparagraph 6.1.3.

b. Report all device failures which occur. The report content and format shall be in accordance with the procedures described in subparagraph 6.1.4.

Inventory and failure data required by this Order shall be submitted to the USGS Conservation Manager in the appropriate regional office.

6.1 *Data and Reporting Requirements.*

6.1.1 *Format.* Inventory and failure data shall be submitted in a format containing the same information that is in the Safety Device Inventory Report (Form 9–1994) and the Safety Device Failure Report Form (Form 9–1995) and as outlined in the respective User's Instruction Booklets. Copies of the forms and booklets may be obtained from the USGS Conservation Manager in the appropriate regional office.

The specific method of submitting the required data may be selected from the following:

a. USGS Forms 9–1994 and 9–1995, using a standard coding convention (e.g., all letters capitalized, Z, I, letter C, number 0).

b. ADP card decks of standard 80-column cards.

c. Magnetic tapes which are 9-track, 800 BPI, unlabeled, blocking cannot exceed 1040 characters, odd parity, single gap (i.e., compatible with IBM equipment EBCDIC).

6.1.2 *Device Coverage.* Inventory and failure reports are to be submitted on the safety- and pollution-prevention devices on offshore structures, including satellites and jackets, which produce or process hydrocarbons, and the hydrocarbon pipelines thereon. These reports shall be submitted on the following:

a. Blowdown Valve—(BDV)
b. Burner Flame Detector—(BSL)
c. Check Valve—(FSV)
d. Combustible Gas Detector—(ASH)
e. Emergency Shutdown Valve—(ESD)
f. Level Sensor:
   High—(LSH)
   Low—(LSL)
   Hi/Lo—(LSHL)
g. Pressure Sensor:
   High—(PSH)
   Low—(PSL)
   Hi/Lo—(PSHL)
h. Relief Valve—(PSV)
i. Shutdown Valve—(SDV)
j. Subsurface-Safety Valve—(SSSV)
k. Surface-Safety Valve—(SSV)
l. Temperature Sensor:
   High—(TSH)
   Low—(TSL)
   Hi/Lo—(TSHL)
m. Valve Actuator on, the shutdown valve, the blowdown valve, the surface-safety valves—(VA)

6.1.3 *Device Inventory Reporting.*

6.1.3.1 *Initial Inventory.* a. For platforms in existence at the time this Order becomes effective, a complete inventory of the safety and pollution-prevention devices shall be submitted no later than 6 months after the effective date of this Order.

b. For platforms completed after this Order becomes effective, a complete inventory of the safety and pollution-prevention devices shall be submitted no later than 1 month after the initial platform production date.

6.1.3.2 *Inventory Updates.* An updating of or addition/deletion to the latest inventory shall be submitted on a monthly basis so as to maintain a current and accurate data base. The inventory will be updated by using the contents of the Safety Device Inventory Report (Form 9–1994) and the Safety Device Failure Report (Form 9–1995).

Inventory updating due to the addition, deletion, or chargeout of a device is accomplished by the lessee's reporting of all the data required on the Safety Device Inventory Report (9–1994).

Whenever a device fails and is either replaced with a new device or "fixed" and put back into service, the inventory shall be

updated to reflect this change. Inventory updating, due to the failure of a device, will be performed by the USGS, using the contents of the Safety Device Failure Report (Form 9–1995). Inventory updating information shall be received no later than 30 days following the month in which the device change was made.

6.1.3.3 *Inventory-Reporting Methods.* Inventory data shall be reported either on the Safety Device Inventory Reporting forms (Form 9–1994), punched cards, or magnetic tapes. The reports shall contain all of the required information in the standard format as described in subparagraph 6.1.1.

6.1.3.4 *Inventory Verification.* The device inventory shall be verified by the lessee to ensure that the inventory data base is maintained on a current basis and that changes are being incorporated as they occur. The verification shall be accomplished no more frequently than once each 6-month period. When verification is required, the USGS will provide the lessee with a copy of the information on record, in the lessee's selected reporting format. The lessee shall review the information and either submit a letter stating that the information is correct, or make the appropriate corrections to the information provided by the USGS. The letter or appropriate corrections shall be received no later than 30 days following the month in which the inventory information which is to be verified was forwarded to the lessee.

6.1.3.5 *Inventory-Reporting Deviation.* A lessee may submit an inventory, update, or verification report differing from that described in subparagraph 6.1.3 when authorized by the USGS.

6.1.4 *Device Failure Reporting.*

6.1.4.1 *Failure-Data Submittal.* Device failure data shall be recorded as soon as possible after detecting the failure as defined in subparagraph 6.1.4.3. This data shall be received no later than 30 days following the month in which the failure was detected. This data must contain all of the required information and be submitted in the standard format either on Safety Device Failure Report forms (Form 9–1995), punched cards, or magnetic tape, as previously described in subparagraph 6.1.1. Information on the failed device must match that previously submitted in inventory reporting. A formal failure analysis is not required by this Order, but each failed device shall undergo sufficient test/disassembly to establish the basic cause(s) of the failure.

6.1.4.2 *Failure-Data Verification.* After receipt of the complete failure data from the lessee, a printout shall be made of all failures by manufacturer, model, and reported cause. Each manufacturer listed shall be furnished a copy of the printout containing the reported failures of his devices only. If he disagrees with the reported failure causes, he is invited to investigate the questioned causes in coordination with the reporting lessee and provide a coordinated reply within 30 days after receipt of the printout. If no reply is received within that time period, the originally reported causes shall be considered to be correct, and the data shall be evaluated accordingly.

6.1.4.3 *Failure Definition.* The safety and pollution-prevention device Failure and Inventory Reporting System does not differentiate between a malfunction and a failure. For the purpose of this program, a failure is defined as the inability of a device to perform its designed function within specified limits. A device is considered to have failed if it does not operate (perform its function) as required within the specified tests' tolerances.

A failure report is not required for:

a. Adjustments made within specified tolerances.

b. Adjustments required due to changes in operating conditions.

7. *Crane Operations.* Cranes shall be operated and maintained to ensure the safety of facility operations in accordance with the provisions of "API Recommended Practice for Operation and Maintenance of Offshore Cranes," API RP 2D, October 1972, or subsequent revisions which the Chief, Conservation Division, has approved for use. Records of inspection, testing, maintenance, and crane operators qualified in accordance with the provisions of API RP 2D shall be kept in the field area for a period of 2 years.

"API Specification for Offshore Cranes," API Specification 2C, February 1972, or subsequent revisions which the Chief, Conservation Division, has approved for use, shall be used as a guideline for the selection of cranes.

8. *Employee Orientation and Motivation Programs for Personnel Working Offshore.* The lessee shall make a planned, continuing effort to eliminate accidents due to human error. This effort shall include the training of personnel in their functions. A program to achieve safe and pollution-free operations shall be established. This program shall include instructions in the provision of "API Recommended Practice Orientation Program for Personnel Going Offshore for the First Time," API RP T–1, January 1974, or subsequent revisions which the Chief, Conservation Division, has approved for use. "API Employee Motivation Programs for Safety and Prevention of Pollution in Offshore Operations," API Bulletin T–5, September 1974, or subsequent revisions which the Chief, Conservation Division, has approved for use, shall be used as a guide in developing employee safety and pollution-prevention motivation programs.

9. *Requirements for Drilling Rigs.*

9.1 *Fixed Structures.* The following requirements contained in this Order are applicable to drilling rigs on fixed structures:

a. Subparagraph 5.1.10, "Electrical Equipment."

b. Subparagraph 5.4, "Welding Practices and Procedures."

c. Paragraph 8, "Employee Orientation and Motivation Programs for Personnel Working Offshore."

9.2 *Mobile Drilling Units.* The following requirements contained in this Order are applicable to drilling rigs on mobile drilling units:

a. Subparagraph 5.4, "Welding Practices and Procedures."

b. Paragraph 8, "Employee Orientation and Motivation Programs for Personnel Working Offshore."

10. *Departures.* All departures from the requirements specified in this Order shall be subject to approval, pursuant to 30 CFR 250.12(b).

Approved:

Don E. Kash,

Chief, Conservation Division.

OCS Order No. 7

Paragraph 1

Comments. One commenter stated that the requirements of "This section should flatly prohibit any pollution of the ocean. Effluent limitations should be set for all discharges and should be based on best available technology."

Discussion. A number of studies have been done on the impacts of the disposal of drilling mud into the Pacific, Cook Inlet (Tanner Bank), and around live-bottom areas in the Gulf of Mexico. None of these studies have indicated significant detrimental impacts as a result of drilling muds. We, therefore, do not believe that it is appropriate to totally prohibit the discharge of muds; but to closely monitor the disposal practices and to restrict the discharges in areas that may be sensitive, such as the coral reefs and live-bottom fishing banks.

Comments. One commenter suggested that "In addition to the list of drilling mud components and special mud additives provided as a part of the Application for a Permit to Drill, individual well records should be maintained on the quantity, concentrations and components of the drilling muds * * *."

Discussion. Lessees are required to submit a detailed list of the quantities of drilling mud used and of the components of drilling mud. It is, however, very difficult to determine the concentrations of the various substances which are discharged, because of the variable amount of dilution associated with each discharge. The dilution of mud, which is discharged with the cuttings, is dependent upon the current and water depth. Excess mud which is generated during drilling is normally stored in reserve tanks. When the reserve tanks are full, excess mud is diluted and discharged as required to maintain the desired levels in the storage tanks. When drilling is completed, heavily weighted mud may be saved and used on subsequent development wells (mud cannot be reused on exploratory wells because of the presence of microscopic, formation-identifying, fossils) or the entire volume of mud may be diluted and discharged, after approval by the District Supervisor.

In order to assess the environmental effect of discharging drilling mud, a detailed chemical and biological survey has to be conducted during the drilling operation. This is not practical or necessary at every drill site. Such surveys have been run in the Gulf of Mexico, Cook Inlet, and Pacific areas with no indications of detrimental effects from the muds and cuttings discharged. These surveys indicate that the amount of dilution which takes place prior to discharge and the

subsequent dilution in the sea is sufficient to assure the protection of the environment.

Subparagraph 1.1.1

Comments. In comments on subparagraph 1.1.1 (1.1.2), several commenters objected to the requirement that approval of the disposal of drilling mud into the ocean must be obtained from the District Supervisor. One commenter claimed that "These requirements are redundant since the operator is required to provide data on the proposed method of disposal in the Application for Permit to Drill * * *."

Discussion. We do not believe this requirement is redundant because environmental conditions may change after the proposed method of disposal has been approved. Each mud-disposal program will be approved on a site-specific basis, considering the biologic and environmental conditions. We recognize that to date the disposal of drilling muds has not resulted in any negative impacts in the Gulf of Mexico or in other offshore areas. However, we must assure that discharges do not impact potentially sensitive areas, particularly coral reefs and fishing banks where there has been no drilling.

Comments. One commenter asked the following questions pertaining to the District Supervisor's decision to approve or disapprove the method of disposal of drilling mud: "* * * on what basis does the Supervisor make his decision? Does he contact the proper State fisheries personnel for site specific information first?"

Discussion. In making a decision to approve or disapprove the method of disposal of drilling mud, the District Supervisor considers information contained in the following documents which are required by 30 CFR 250.34:

1. Lessee's Environmental Report (Exploration).
2. Lessee's Environmental Report (Development/Production).
3. Oil and Gas Supervisor's Environmental Assessment of 1 or 2 above.
4. Environmental Impact Statement, if required by 3 above.

When these documents identify biologically sensitive areas, the District Supervisor consults with the appropriate Federal and State agencies, prior to approving the method of disposal of drilling mud.

Comments. One commenter stated that "Currently three agencies address the question on drilling mud disposal * * *," and suggested that the last two sentences should be revised as follows: "Approval of the drilling mud disposal method by the District Supervisor shall be consistent with any lease stipulations or other Federal regulations."

Discussion. We are currently working with the Environmental Protection Agency (EPA) to develop a memorandum of understanding that will deal with the disposal of drilling muds, cuttings, and other waste materials. The following sentence was added to recognize the EPA's authority in the regulation of discharges: "The disposal of drilling mud is subject to the Environmental Protection Agency's permitting procedures, pursuant to the Federal Water Pollution Control Act as amended."

Subparagraph 1.1.2

Comments. In a comment on subparagraph 1.1.2 (1.1.3), it was suggested that the requirements "* * * should be expanded to assure adherence to air quality and performance standards under the Clean Air Act Amendments of 1977."

Discussion. The United States Geological Survey (USGS) is currently developing air quality regulations in accordance with the OCS Lands Act Amendments of 1978.

Comments. One commenter suggested that "Periodic monitoring of this (hydrocarbon handling) equipment should be conducted to assure that it is functioning properly."

Discussion. This requirement is contained in OCS Order No. 5.

Subparagraph 1.1.3

Comments. Several commenters recommended that the term "mobile drilling unit" be deleted from this requirement in subparagraph 1.1.3 (1.1.4). One commenter interpreted that mobile drilling units were the responsibility of the U.S. Coast Guard (USCG). Another commenter felt that these requirements are inconsistent with OCS Order No. 5.

Discussion. The USGS review of the comments on the requirements of the proposed subparagraph 4.1.7, "Curbs, Gutters, and Drains," of the proposed OCS Order No. 5, and the comments received on subparagraph 1.1.4, "Curbs, Gutters, and Drains," of the proposed OCS Order No. 7, indicated that the requirements of these subparagraphs should be addressed only in OCS Order No. 7. Therefore, this paragraph was deleted from OCS Order No. 5 and the requirements were included in subparagraph 1.1.3 of OCS Order No. 7. The subparagraph has been retitled and rewritten to recognize the U.S. Coast Guard's authority to prescribe requirements for deck drainage systems on mobile drilling units which are not associated with the drilling operation. This revision is consistent with the Memorandum of Understanding (MOU) between the USCG and the USGS dated April 11, 1977. Comments which were received on subparagraph 4.1.7 of OCS Order No. 5 are discussed below.

Comments. Several commenters were concerned with the second sentence which required: "All walking and working surfaces shall be kept free of all liquid accumulations." The consensus of opinion was that this requirement was not practical and it would be impossible to comply with.

Discussion. This sentence has been changed to the following: "All walking and working surfaces shall be equipped with proper drainage to provide safety for personnel and to prevent pollution."

Comments. It was recommended that "Sump piles should also be closed, not open to the ocean and the language of the paragraph should be changed to make this clear."

Discussion. The OCS Orders for the Pacific, Alaska, and Atlantic areas were revised to require all drainage to be collected in a closed sump. The Gulf of Mexico OCS Order was revised to require the use of existing open-ended sump piles to be discontinued within 12 months after the effective date of the Order.

Comments. A commenter stated that "It is not mentioned whether petroleum contaminants would be passed through an oily water separator, incinerated on board the vessel, or transported to shore for disposal."

Discussion. A sentence was added to require the contaminants which are removed from sumps to be disposed of in a manner which will not create pollution.

Subparagraph 1.1.4

Comments. Several comments on the proposed subparagraphs 1.1.5, "Fixed Structure Discharges," and 1.1.6, "Mobile Drilling Unit Discharges," suggested that these subparagraphs should reflect the Environmental Protection Agency's (EPA)'s authority to regulate discharges from mobile drilling units and fixed drilling platforms.

Discussion. It has been determined that the EPA has jurisdiction over all types of discharges on the OCS, regardless of the source. Therefore, the contents of the original subparagraphs 1.1.5 and 1.1.6 have been incorporated into a new subparagraph 1.1.4, "Discharges from Fixed Platforms or Structures and Mobile Drilling Units." The revised subparagraph states that discharges from fixed platforms or structures and mobile drilling units are subject to EPA's permitting procedures, pursuant to the Federal Water Pollution Control Act, as amended.

Former Subparagraph 1.1.6

Comments. It was suggested that the proposed subparagraph 1.1.6, "Mobile Drilling Unit Discharges," placed no restrictions on the amount of oily substances from the mobile drilling unit, and the USGS should adopt the following language: "Discharges from mobile drilling units, including produced water and deck drainage shall contain no free oil and shall not cause a sheen to form on the surface of the ocean.

*Alternatively, a 50 ppm oil standard could be established."

Another commenter suggested that the term "free oil," which was used in the original subparagraph 1.1.1, "Oil-Cut Drilling Mud," should be defined.

Discussion. These suggestions were not adopted. The term "free oil" has been deleted from the proposed subparagraphs 1.1.1 and 1.2.1. The final versions of subparagraphs 1.1.1, 1.1.4, and 1.2.1 reflect EPA's authority to regulate discharges from all sources. The EPA is currently developing revised guidelines for the approval of discharge permits. When these guidelines are published, this Order will be revised, if necessary, to maintain consistency.

Subparagraph 1.2.1

Comments. A commenter stated, "Drill cuttings, sands and other well solids, unassociated with free oil, should not be allowed to be dumped into the ocean with no regulation whatsoever."

Discussion. As previously stated, the subparagraph was revised to reflect EPA's authority to regulate discharges from all sources. A sentence was also added to require the District Supervisor's approval of the method of disposal of drill cuttings, sand, and other well solids.

Comments. One commenter stated that "The term 'all of the free oil has been removed' is too broad and restrictive a term. The word 'all' would infer absolutely no oil would be present. It would be more realistic to specify a mg/l value. Once solids have been exposed to oil it is doubtful that absolutely all of it could be removed by conventional treatment."

Another commenter suggested that "* * * under certain conditions, disposal of drilling muds, and other solids from which the 'free' oil has been removed could violate the effluent guidelines for disposal of these materials by creating free oil on the surface waters. We suggest that the wording of 1.1.1 and 1.2.1 be revised to be consistent with EPA's effluent guidelines."

Discussion. Subparagraphs 1.1.1, 1.2.1, and 1.4.1 have been revised in response to these comments. Refer to the discussion for former subparagraph 1.1.6.

Subparagraph 1.2.3

Comments. One commenter suggested that the location and description of equipment which is disposed of into the ocean under emergency conditions should be reported to the U.S. Coast Guard.

Discussion. This suggestion was adopted. The subparagraph was revised to require that equipment which is disposed of into the ocean under emergency conditions shall be reported to the District Supervisor and to the U.S. Coast Guard in accordance with paragraph 4 of OCS Order No. 1.

Subparagraph 2.1

Comments. A recommendation was made to require "All personnel, including those engaged in drilling operations, platform and pipeline construction and supply boat operations, shall be thoroughly instructed in the procedures and methods of operation of the fishing industry and in the measures which can be taken to avoid potential conflicts between the fishing and petroleum industries."

Discussion. In those Areas where conflicts between the fishing and petroleum industries have occurred, special training may be required by lease stipulations.

Subparagraph 2.2

Comments. A commenter stated, "All facilities whether manned or unattended should be required to have a pollution monitoring system in place and functioning at all times. Monitoring reports should be filed periodically and there should be periodic testing of the monitoring system to determine its accuracy."

Discussion. The Order already requires the lessee to inspect all facilities daily. Subparagraph 2.3 outlines how spills are to be reported. We believe that daily inspection of the facilities is the best method for detecting pollution or conditions which will cause pollution. Production equipment sensors are designed to automatically shut down production in the event of a malfunction, as required by OCS Order No. 5. No effective equipment has been developed for monitoring pollution around a platform.

Subparagraph 2.2.2

Comments. The majority of the commenters objected to the requirement to inspect unattended facilities daily. One commenter stated, "Daily inspection of unattended facilities would be excessively burdensome to the operators and under certain meteorological conditions dangerous to inspectors." The commenters suggested that inspections be required at frequent intervals prescribed by the District Supervisor.

Discussion. The requirement was not changed. It is the USGS' belief that early detection of situations that could cause pollution is the key to pollution prevention and the key to a rapid cleanup effort when a spill has occurred.

Subparagraph 2.3

Comments. Two commenters suggested that this subparagraph should require oil spills to be reported directly to the U.S. Coast Guard (USCG) and to the District Supervisor. Another commenter suggested that spills should be reported "* * * orally to the District Supervisor and in accordance with the reporting structure outlined in the Oil Pollution Liability Regulations (33 CFR 153.203) and confirmed in writing to the District Supervisor."

Discussion. The latter suggestion was adopted. The following sentence was added to the subparagraph: "All spills of oil and liquid pollutants shall also be reported in accordance with the procedure contained in 33 CFR 153.203." The USGS, the USCG, and the EPA are currently working to develop an MOU which will clarify the reporting requirements. When this MOU is finalized, this Order will be revised, if necessary, to maintain consistency.

Subparagraph 2.3.1

Comments. Several commenters expressed concern over the volume/time schedule for the reporting of oil spills.

Discussion. It has been found necessary through operational experience to set a limit on the size of an oil spill which poses a threat to the environment and could be removed or should require an onsite investigation. Oil spills of less than 1 cubic meter (6.3 barrels) are not considered to be a major threat to the environment. Spills greater than 1 cubic meter (6.3 barrels) have the potential to be a major threat. Therefore, the subparagraph provides for the appropriate degree of urgency in the reporting requirements by stipulating the 12-hour and without-delay reporting time periods. Regardless of the time period specified, the lessee is required by 33 CFR 153.203 to report without delay any oil spill which threatens public health or welfare or results in critical public concern. It should be noted that the National Oil and Hazardous Substances Pollution Contingency Plan defines a minimum discharge of oil in coastal waters as 10,000 gallons (238 barrels). The reporting procedure does not lessen the operator's responsibility to report the pollution incident, remove the pollutant, or be responsible for the results of any pollution damage.

Subparagraph 2.3.2

Comments. One commenter suggested that the requirement that lessees shall notify each other upon observation of equipment malfunction or pollution resulting from another's operations is an unnecessary requirement which should be deleted from the Order.

Discussion. This suggestion was not adopted. The intent of the Order is to promote mutual pollution-prevention efforts among lessees in a given area, especially on unmanned facilities.

Subparagraph 3.1

Comments. Several commenters expressed concern over the requirement that pollution-control equipment shall be maintained at an offshore location or at locations required by the Supervisor. One commenter suggested that "* * * this requirement is not specific enough as to the location of the equipment, nor does it necessarily provide an appropriate level of protection to the marine environment, particularly in view of the delay authorized in reporting spills of less than five cubic meters * * *." The commenter recommended that the subparagraph be revised as follows:

"3.1 *Equipment.* As a minimum, a sufficient amount of standby pollution control equipment should be maintained at each site to permit the efficient and timely removal of up to 5.0 cubic meters of oil. Additional containment and removal equipment, sufficient to control all spills larger than 5.0 cubic meters should be readily accessible to the operator. Accessibility may be determined by direct ownership, joint ownership, cooperative venture or contractual agreement. This shall include * * *."

Discussion. The first sentence of the subparagraph was revised as follows: "Pollution-control equipment and materials shall be maintained by, or shall be available to, each lessee at an offshore location, or at a location approved by the Supervisor." It has been determined that certain pollution-control equipment can be stored at offshore locations while other equipment requires storage either onshore or possibly on floating equipment in estuary areas. Due to platform size, configuration, or location, it may be undesirable to store certain pollution-control equipment on an active drilling or production platform. In the event of a fire, an explosion, or a blowout, the equipment could be destroyed or be inaccessible. The intent of the revised language is to assure that pollution-control equipment will be stored in areas that provide the minimum response time, if an oil spill occurs. The Supervisor evaluates the adequacy of the response time on a case-by-case basis during his review of the Contingency Plans.

Comments. One commenter suggested that the third sentence of the requirement of this subparagraph should be changed to state "The use of chemical agents or other additives shall be permitted only * * *" rather

than stating "The use of chemicals shall be permitted only * * *." This language would be consistent with Annex X of the National Oil and Hazardous Substances Pollution Contingency Plan.

Discussion. This suggestion has been adopted. However, this requirement is related to spill control and removal; therefore, the sentence was added as the last sentence of paragraph 5, "Spill Control and Removal."

Comments. A commenter recommended that "* * * in addition to monthly inspections, all pollution control equipment on drilling rigs be inspected and tested by factory representatives or other knowledgeable personnel prior to well-spudding operations."

Discussion. This recommendation was not adopted. We believe the drills and training required by paragraph 4 of this Order provide an adequate test of the performance of the men and equipment.

Subparagraph 3.2

Comments. One commenter stated that his State would like to review Oil Spill Contingency Plans. The commenter also requested that "* * * the State be included as a party required to be notified in the case of an oil discharge."

Discussion. Oil Spill Contingency Plans are public information, as specified in OCS Order No. 12, and they will be made available by the Supervisor. We do not believe that the Order should require the lessee to notify the affected States when an oil discharge occurs. The National Oil and Hazardous Substances Pollution Contingency Plan, Title 40 CFR Part 1510.34(c), invites affected States to furnish liaison to the Regional Response Team (RRT) for planning and preparedness activities. When the Team is activated for a pollution emergency, the affected State or States are invited to participate in RRT deliberations.

Our review of this comment indicated that requirements for an annual review of the Contingency Plan should be included in subparagraph 3.2 rather than in paragraph 6, "Contingency Plan Review"; therefore, former paragraph 6 was deleted.

Subparagraph 3.2c

Comments. One commenter suggested that "* * * the term 'biological sensitivity' is too restrictive to cover the various types of damage which occur as a result of oil spills.". The commenter stated that "It is also considered necessary to identify the possible impact areas before a protection plan can be devised. It was recommended that 3.2c be revised as follows: "Provisions for identifying and protecting areas of special environmental sensitivity."

Discussion. This suggestion was adopted. The addition of the words "for identifying" is consistent with 30 CFR 250.34–3.

Subparagraph 3.2e(3)

One commenter stated that "In order to provide the person in charge of cleanup operations with the best information available as to the status and progress of the cleanup, the operations center should be located as close as possible to the spill incident." The commenter recommended that the following sentence be added to the subparagraph: "The location selected should be as close as possible to the probable spill area. The operations center may be either a fixed or mobile facility, provided that adequate communications are available."

Discussion. This recommendation was not adopted. It is assumed that the lessee will exercise prudent judgment in the selection of a preplanned location for the oil-spill-response operations center. If a lessee selected a location which was excessively remote from the probable spill areas, the Supervisor has the discretion to disapprove the Oil Spill Contingency Plan.

Paragraph 4

Comments. One commenter recommended "* * * that an additional paragraph be added to section 4 stating that at least one supervisory individual on each offshore unit must receive formal oil spill control instructions and be so certified by the instructing institution."

Discussion. This recommendation was adopted. For editorial clarity, the requirements were segregated into two subparagraphs, 4.1, "Drills," and 4.2, "Training."

Comments. Several commenters expressed concern over the adequacy of onshore drills. It was suggested that the phrase " 'onshore locations where pollution and containment equipment is based,' should be deleted." Other commenters expressed concerns over the requirement for "A drill schedule acceptable to the Supervisor * * *." Other commenters expressed concern over the adequacy of drills where all equipment is not deployed.

Discussion. The new subparagraph 4.1, "Drills," has been rewritten in response to some of these comments. The provision for drills at onshore locations has been deleted. The sentence, "All equipment need not be deployed at each drill," has been deleted and replaced with the following two sentences: "A time schedule with a list of equipment to be deployed shall be submitted to the Supervisor for approval. The drill schedule shall provide sufficient advance notice to allow U.S. Geological Survey personnel to witness any of the drills."

These revisions recognize the Supervisor's authority to approve the timing of the drills and to make a judgment on the adequacy of the list of equipment to be deployed. The Supervisor would not require the deployment of duplicate sets of equipment, if adequate training and deployment capability could be demonstrated by the deployment of one set.

Paragraph 5

Comments. One commenter suggested: "The policy of the United States requiring the removal of spilled oil should be unequivocally stated. Also stated should be a preference for the use of mechanical removal methods, such as the use of sorbents, booms, and skimmers over the use of chemical agents."

Discussion. This suggestion was not adopted. The policy of the United States regarding the lessee's responsibility for the removal of pollutants is clearly stated in 30 CFR 250.43 and 33 CFR 153. Methods and procedures for the removal of discharged oil are detailed in 33 CFR 153.305. The respective responsibilities of the USGS and the USCG are defined in the MOU between the Department of the Interior and the Department of Transportation, dated August 16, 1971. We believe the pollution removal policies of the United States are adequately covered in these documents.

U.S. Department of the Interior; Geological Survey, Conservation Division

OCS Order No. 7, Effective July 1, 1979; Pollution Prevention and Control

This Order is issued pursuant to the authority prescribed in 30 CFR 250.11 and in accordance with 30 CFR 250.43. The lessee shall comply with the following requirements.

1. *Pollution Prevention.* During the exploration, development production, and transportation of oil and gas, the lessee shall prevent pollution of the ocean. Furthermore, by the disposal of waste materials into the ocean, the lessee shall not create conditions which will adversely affect the public health, life, property, aquatic life, wildlife, recreation, navigation, commercial fishing or other uses of the ocean.

1.1 *Liquid Disposal.*

1.1.1 *Drilling-Mud Components.* The lessee shall submit, as a part of the Application for Permit to Drill (Form 9–331C), a detailed list of drilling-mud components including the common chemical or chemical trade name of each component, a list of the drilling-mud additives anticipated for use in meeting special drilling requirements, and the proposed method of drilling-mud disposal. The disposal of drilling mud is subject to the Environmental Protection Agency's permitting procedures, pursuant to the Federal Water Pollution Control Act, as amended. Approval of the method of drilling-mud disposal into the ocean shall be obtained from the District Supervisor; each request will be decided on a case-by-case basis.

1.1.2 *Hydrocarbon-Handling Equipment.* All hydrocarbon-handling equipment for testing and production such as separators, tanks, and treaters shall be designed and operated to prevent pollution. Maintenance or repairs which are necessary to prevent pollution of the ocean shall be undertaken immediately.

1.1.3 *Curbs, Gutters, and Drains for Fixed Platforms or Structures and Mobile Drilling Units.*

Gulf of Mexico:

a. *Fixed Platforms or Structures.*

(1) *New Installations.* Curbs, gutters, and drains shall be installed in all deck areas so that all contaminants are collected in a closed sump. When open decks are used, drip pans or the equivalent shall be placed under equipment and piped to a closed sump. Closed sumps shall automatically maintain fluid at a level sufficient to prevent the discharge of oil into the ocean. Contaminants that are removed from sumps shall be disposed of in a manner which will not create pollution.

All walking and working surfaces shall be equipped with proper drainage to provide safety for personnel and to prevent pollution.

(2) *Existing Installations.* The use of open-ended sump piles as a processing device to treat or skim liquid hydrocarbons or to dispose of sand shall be discontinued within the 12-month period which immediately follows the effective date of this Order, or within a period of time approved by the District Supervisor.

b. *Mobile Drilling Units.* Curbs, gutters, and drains which collect contaminants associated with the drilling operation on a mobile drilling unit shall be installed as required by subparagraph 1.1.3a.

Curbs, gutters, and drains which collect contaminants not associated with the drilling operation are subject to regulation by the U.S. Coast Guard.

Pacific, Gulf of Alaska, Atlantic

a. *Fixed Platforms or Structures.* Curbs, gutters, and drains shall be installed in all deck areas to collect all contaminants in a closed sump. When open decks are used, drip pans or the equivalent shall be placed under equipment and piped to a closed sump. Closed sumps shall automatically maintain fluid at a level sufficient to prevent the discharge of oil into the ocean. Contaminants that are removed from sumps shall be disposed of in a manner which will not create pollution.

All walking and working surfaces shall be equipped with proper drainage to provide safety for personnel and to prevent pollution.

b. *Mobile Drilling Units.* Curbs, gutters, and drains which collect contaminants associated with the drilling operation on a mobile drilling unit shall be installed as required by subparagraph 1.1.3a.

Curbs, gutters, and drains which collect contaminants not associated with the drilling operation are subject to regulation by the U.S. Coast Guard.

1.1.4 *Discharges from Fixed Platforms or Structures and Mobile Drilling Units.* Discharges from fixed platforms or structures and mobile drilling units, including sanitary waste, produced water, drilling mud, and deck drainage, are subject to the Environmental Protection Agency's permitting procedures, pursuant to the Federal Water Pollution Control Act, as amended.

1.2 *Solid Material Disposal.*

1.2.1 *Well solids.* The disposal of drill cuttings, sand, and other well solids containing oil is subject to the Environmental Protection Agency's permitting procedures, pursuant to the Federal Water Pollution Control Act, as amended. Approval of the method of disposal of drill cuttings, sand, and other well solids shall be obtained from the District Supervisor.

1.2.2 *Containers.* Containers and other similar solid-waste materials shall not be disposed of into the ocean.

1.2.3 *Equipment.* Disposal of equipment into the ocean is prohibited except under emergency conditions. The location and description of any equipment disposed of into the ocean shall be reported to the District Supervisor and to the U.S. Coast Guard in accordance with paragraph 4 of OCS Order No. 1.

2. *Personnel, Inspections, and Reports.*

2.1 *Personnel.* The lessee's personnel shall be instructed in the techniques of equipment maintenance and operation for the prevention of pollution. Contractor personnel providing services offshore shall be informed in writing, prior to executing contracts, of the lessee's obligations to prevent pollution and of the provisions of this Order.

2.2 *Pollution Inspections.*

2.2.1 *Manned Facilities.* Manned drilling and production facilities shall be inspected daily to determine if pollution is occurring. Maintenance or repairs which are necessary to prevent pollution of the ocean waters shall be undertaken and performed immediately.

2.2.2 *Unattended Facilities.* Unattended facilities, including those equipped with remote control and monitoring systems, shall be inspected daily or at intervals prescribed by the District Supervisor to determine if pollution is occurring. Necessary maintenance or repairs shall be made immediately.

2.3 *Pollution Reports.* All spills of oil and liquid pollutants shall be reported orally to the District Supervisor and shall be confirmed in writing. All reports shall include the cause, location, volume of spill, and action taken. Reports of spills of more than 5.0 cubic meters (31.5 barrels) shall include information on the sea state, meteorological conditions, size, and appearance of slick. All spills of oil and liquid pollutants shall also be reported in accordance with the procedure contained in 33 CFR 153.203.

2.3.1 *Spills.* Spills shall be reported orally within the following time limits:

a. Within 12 hours, if spills are 1.0 cubic meters (6.3 barrels) or less.

b. Without delay, if spills are more than 1.0 cubic meter (6.3 barrels).

2.3.2 *Observed Malfunctions.* Lessees shall notify each other of observed pollution resulting from another's operation.

3. *Pollution-Control Equipment and Materials and Oil Spill Contingency Plans.* The lessee shall submit a description of procedures, personnel, and equipment that will be used in reporting, cleanup, and prevention of the spread of any pollution resulting from an oil spill which might occur during exploration or development activities. The following subparagraphs describe the minimum requirements for pollution-control equipment and procedures.

3.1 *Equipment and Materials.* Pollution-control equipment and materials shall be maintained by, or shall be available to, each lessee at an offshore location or at a location approved by the Supervisor. The equipment shall include containment booms, skimming apparatus, cleanup materials, and chemical agents which shall be available prior to the commencement of operations. The equipment and materials shall be inspected monthly and maintained in a state of readiness for use. The results of the inspections shall be recorded and maintained at the site.

3.2 *Oil Spill Contingency Plans.* The lessee shall submit an Oil Spill Contingency Plan for approval by the Supervisor, prior to the approval of an Exploration Plan or a Development and Production Plan. Oil Spill Contingency Plans shall be reviewed annually. All modifications of the Oil Spill Contingency Plan and the results from the review of the plan shall be submitted to the Supervisor for approval. The Oil Spill Contingency Plan shall contain the following:

a. Provisions to assure that full resource capability is known and can be committed during an oil spill, including the identification and inventory of applicable equipment, materials, and supplies which are available locally and regionally, both committed and uncommitted, and the time required for deployment of the equipment.

b. Provisions for vaying degrees of response effort depending on the severity of the oil spill.

c. Provisions for identifying and protecting areas of special biological sensitivity.

d. Establishment of procedures for the purpose of early detection and timely notification of an oil spill including a current list of names, telephone numbers, and addresses of the responsible persons and alternates on call to receive notification of an oil spill; and the names, telephone numbers, and addresses of regulatory organizations and agencies to be notified when an oil spill is discovered.

e. Provisions for well-defined and specific actions to be taken after discovery and notification of an oil spill, including:

(1) Specification of an oil-spill-response operating team consisting of trained, prepared, and available operating personnel.

(2) Predesignation of an oil-spill-response coordinator who is charged with the responsibility and is delegated commensurate authority for directing and coordinating response operations.

(3) A preplanned location for an oil-spill-response operations center and a reliable communications system for directing the coordinated overall response operations.

(4) Provisions for disposal of recovered spill materials.

4. *Drills and Training.*

4.1 *Drills.* Drills for familiarization with pollution-control equipment and operational procedures shall be held by the lessee. The personnel identified as the oil-spill-response operating team in the Contingency Plan shall participate in these drills. The drills shall be realistic and shall include deployment of equipment. A time schedule with a list of equipment to be deployed shall be submitted to the Supervisor for approval. The drill schedule shall provide sufficient advance notice to allow U.S. Geological Survey personnel to witness any of the drills. Drills shall be recorded, and the records shall be made available to U.S. Geological Survey personnel. Where drill performance and results are deemed inadequate, the Supervisor may require an increase in the frequency or a change in the location of the drills until satisfactory results are achieved.

4.2 *Training.* The lessee shall ensure that training classes for familiarization with pollution-control equipment and operational procedures are provided for the oil-spill-response operating team. The supervisory personnel responsible for directing the oil-spill-response operations shall receive oil-spill-control instruction suitable for all seasons. The lessee shall retain course-completion certificates or attendance records

issued by the organization where the instruction is provided. These records shall be available to any authorized representative of the U.S. Geological Survey, upon request.

5. *Spill Control and Removal.* Immediate corrective action shall be taken in all cases where pollution has occurred. Corrective action taken under the lessee's Oil Spill Contingency Plan shall be subject to modification when directed by the Supervisor. The primary jurisdiction to require corrective action to abate the source of pollution shall remain with the Supervisor, pursuant to the provisions of this Order and the Memorandum of Understanding (MOU) between the Department of Transportation (U.S. Coast Guard) and the Department of the Interior (U.S. Geological Survey) dated August 16, 1971. The use of chemical agents or other additives shall be permitted only after approval by the Supervisor in accordance with Annex X, National Oil and Hazardous Substances Pollution Contingency Plan and in accordance with the previously mentioned MOU.

6. *Departures.* All departures from the requirements specified in this Order shall be subject to approval, pursuant to 30 CFR 250.12(b).

Approval:

Don E. Kash,

Chief, Conservation Division.

OCS Order No. 12

Paragraph 1

Comments. One commenter objected to "the withholding of a lessee's or operator's geophysical and geological information from public scrutiny." This commenter does not believe "5 USS § 552 authorizes such an exemption." The commenter believes "reports should be available for public inspection."

Discussion. Pursuant to revisions of the Freedom of Information Act [5 U.S.C. § 552(b)(9)], Title 43 CFR Part 2 was revoked in its entirety and a revised Part 2 was adopted. Specifically, § 2.13(c), "Statutory Exemptions," (9) was revised to provide for the exemption of geophysical and geological data. These revised regulations became effective when the revisions were published in the **Federal Register**, Vol. 40, No. 34, Wednesday, February 19, 1975.

In accordance with the authority vested in the Secretary of the Interior by the Outer Continental Shelf Lands Act of August 7, 1953, Title 30 CFR 250.97 was amended to provide for the release of geophysical data 10 years after the date of submission or after the expiration of the lease, whichever occurs first. This amendment also provided for the release of geological data 2 years after the date of submission or after the expiration of the lease, whichever occurs first. These amendments became effective when signed by the Secretary of the Interior on June 11, 1976. The amendments were subsequently published in the **Federal Register**, Vol. 41, No. 122, Wednesday, June 23, 1976. These amendments are applicable to leases issued after June 11, 1976. Therefore, paragraph 3, "Information Exempt from Public Inspection," has been revised to provide for the implementation of these regulation amendments.

Paragraph 2

Comments. It was suggested that records, pertaining to leases and wells, which have been classified as proprietary data and withheld from public information "* * * should be made available to the States at least under such a provision as is included in the Bureau of Land Management's proposed rulemaking published in the September 26, 1977, **Federal Register**. These proposed rules provide that data protected from general release as Public Information shall be available to the Governor's designee on a protected confidential basis."

Discussion. The final revision of the Bureau of land Management's regulation, 43 CFR 3301.8(d), as published in the **Federal Register**, Vol. 43, No. 19, January 27, 1978, states in part: "no data or information determined to be exempt from public disclosure under such Act and regulations shall be made available for public disclosure or provided to any affected state or to the executive of any local government." This final regulation is consistent with 30 CFR 250.34, 250.97, and 43 CFR 2.13. Subparagraph 2.10, "Availability of Data and Information Submitted by Lessees," lists various nonproprietary data which is available.

Comments. One commenter stated that "All information on the monthly reports should be available for public inspection, including the category designated 'Remarks'." The commenter suggested that "No reason is ever given for exempting the remarks from public scrutiny.

The commenter also objected to the withholding of information on "the type, location, and producing interval of the wells," prior to commencement of production.

Discussion. In the "Remarks" section of the monthly report, the operator is usually discussing operational matters concerning producing intervals. This is considered proprietary data and is not available for public scrutiny.

The type, location, and producing interval of wells is also considered proprietary data because this information could be used to develop a contour map of the producing structure. The paragraph was not changed.

Comments. One commenter suggested that "there should be a provision for timely (weekly or montly) cataloging of the records available for public inspection in the Area office."

Discussion. The Order contains a complete listing of the information which is available in the public information room of the Area office. The current status on the receipt of specific information from specific leases or wells is available upon request. The public information room is open to the public during normal working hours. Therefore, the cataloging of the available records is unnecessary.

Subparagraph 2.4

Comments. One commenter suggested that "the casing program for the drive or structural and conductor casings should not be proprietary."

Discussion. The setting depths of all casing strings are based on geological data; therefore, this information is exempt from public disclosure.

Subparagraph 2.10

Comments. One commenter suggested that the phrase "except for those portions which the lessee shall designate, with the Supervisor's approval, as trade secrets and commercial or financial information which is privileged or confidential" be moved from subparagraph 2.10c and inserted at the end of the lead-in sentence. The commenter stated: "In addition to results of site surveys required prior to drilling or placement structures, other information submitted in items (a) through (f) may contain privileged or confidential information which should not be made available for public inspection."

Discussion. The USGS agrees with this comment and has revised the Order accordingly. Subparagraph 2.10c was revised further by adding the phrase, "such as shallow geologic hazards surveys, archaeological/cultural resource surveys, or other surveys related to the placement of platforms or structures." This revision clarified the type of site surveys which are to be made available.

Subparagraph 2.10b

Comments. It was suggested that subparagraph 2.10b be deleted. The commenter suggested that the subparagraph "has several very undesirable aspects" which he believes include:

"1. It reduces competition between the operating companies in that data accumulated at great cost by one company is obtained free by another company.

"2. It reveals proprietary data on performance of a contractor's vessel to his competitor. This again reduces competition.

"3. It is not in the national interest to publish detailed data on performance of our drilling units while receiving nothing in return from foreign nations which can, at least through a third party, obtain the data.

"4. This information is detailed technical data and is not in the form which is of use to the public."

Discussion. We cannot agree that competition will be reduced by furnishing oceanographic data and meteorological data: Each company operating in the OCS will be contributing; therefore, an exchange of data would be mutually beneficial to all. We agree that drilling-vessel performance data should not be made available without the consent of the lessee; therefore, the requirement for the release of performance data was deleted.

Subparagraph 2.10d

Comments. The commenter, quoted in the comments for subparagraph 2.10b, also suggested that this subparagraph be deleted for the same reasons.

Discussion. Subparagraph 2.10d was revised by replacing the words "performance data" with the words "rated capability."

Subparagraph 2.10e

Comments. One commenter stated that "Much of the data required by this section has been acquired through exhaustive and

expensive private research and is, therefore, proprietary in nature." The commenter recommended that the subparagraph be revised to require that proprietary data "shall not be disclosed without prior notification to the affected party and appropriate hearings."

Discussion. The revision of subparagraph 2.10 provides for the exemption of proprietary information with the approval of the Supervisor.

Subparagraph 2.11

Comments. No comments received.

Discussion. In accordance with 30 CFR 250.97, a new subparagraph 2.11, "Expired Leases," was added to provide for the release of information pertaining to expired leases.

Paragraph 3

Comments. One commenter stated that "Legal means should be provided to decide whether or not specific information is or is not proprietary in nature and, therefore, subject to disclosure."

Discussion. As outlined in the discussions of the revision of paragraph 1, paragraph 3 has been revised completely to elaborate on the release of information which is exempt from public inspection. The Freedom of Information Act § 552 sets forth guidelines for the determination of proprietary data. These guidelines are the "legal means" for the determination of proprietary data. The requirements for the release of information have also been set forth in 30 CFR 252.6 as published in the Federal Register, Vol. 43, No. 19, Friday, January 27, 1978.

U.S. Department of the Interior; Geological Survey Conservation Division

OCS Order No. 12, Effective July 1, 1979; Public Inspection of Records

This Order is issued pursuant to the authority prescribed in 30 CFR 250.11 and in accordance with 30 CFR 250.34, 250.97, 252.6, and 43 CFR Part 2. Requests for information made under the Freedom of Information Act, 5 U.S.C. § 552, will be governed by the provisions of 43 CFR Part 2 (40 FR 7304, February 19, 1975).

1. *Filing of Reports.* All reports on forms 9–152, 9–330, 9–331, 9–331 C, 9–1869, 9–1870 and the forms used to report the results of multipoint back-pressure tests shall be filed by the lessee in accordance with the following:

a. All reports submitted on these forms shall include a copy with the words "Public Information" shown on the lower right-hand corner. This copy of the form shall be made available for public inspection.

b. All items on the form not marked "Public Information" shall be completed in full, and such forms and all attachments thereto shall not be available for public inspection.

c. The copy marked "Public Information" shall be completed in full except that the items described in subparagraphs 2.1 through 2.4 below and the attachments relating to such items may be excluded.

2. *Availability of Records.* It has been determined that certain records pertaining to leases and wells in the Outer Continental Shelf (OCS) and submitted under 30 CFR 250 shall be made available for public inspection, as specified below, in the Area office.

2.1 *Form 9–152—Monthly Report of Operations.* All information contained on this form shall be available except the information required in the "Remarks" column.

2.2 *Form 9–330—Well-Completion or Recompletion Report and Log.*

2.2.1 *Prior to Commencement.* Prior to commencement of production, all information contained on this form shall be available except:

a. Item 1a, Type of Well.

b. Item 4, Location of Well, at top production interval and at total depth.

c. Item 22, If Multiple Completion, how many.

d. Item 24, Producing Interval.

e. Item 26, Type Electric and Other Logs Run.

f. Item 28, Casing Record.

g. Item 29, Liner Record.

h. Item 30, Tubing Record.

i. Item 31, Perforation Record.

j. Item 32, Acid, Shot, Fracture, Cement Squeeze, Etc.

k. Item 33, Production.

l. Item 37, Summary of Porous Zones.

m. Item 38, Geologic Markers.

2.2.2 *After Commencement of Production.* After commencement of production, all information shall be available except Item 37, Summary of Porous Zones, and Item 38, Geologic Markers.

2.2.3 *5 Years' Elapsed Time.* If production has not commenced after an elapsed time of 5 years from the date of filing Form 9–330 as required in 30 CFR 250.38(b), excluding the total time that operations and production are suspended by direction of the Secretary of the Interior or his duly authorized representative, and further excluding the total time that operations and production are stopped or prohibited by Court order, all information contained on this form shall be available except Item 37, Summary of Porous Zones, and Item 38, Geologic Markers. Within 90 days prior to the end of the 5-year period, exclusive of exceptions noted above, the lessee shall file a Form 9–330 containing all information requested on the form except Item 37, Summary of Porous Zones, and Item 38, Geologic Markers, to be made available for public inspection. Objections to the release of such information may be submitted with the completed Form 9–330.

2.3 *Form 9–331—Sundry Notices and Reports on Wells.*

2.3.1 *"Request for Approval to."* When used as a "Request for Approval to:" conduct operations, all information contained on this form shall be available except Item 4, Location of Well, at top production interval and at total depth, and Item 17, Describe Proposed or Completed Operations.

2.3.2 *"Subsequent Report of."* When used as a "Subsequent Report of:" operations, and after commencement of production, all information contained in this form shall be available, except information contained in Item 17 pertaining to subsurface locations and measured and true vertical depths for all markers and zones not placed on production.

2.4 *Form 9–331 C—Application for Permit to Drill, Deepen, or Plug Back.* All information contained on this form and the location plat attached thereto shall be available except Item 4, Location of Well at Proposed Production Zone, and Item 23, Proposed Casing and Cementing Program.

2.5 *Form 9–1869—Quarterly Oil-Well-Test Report.* All information contained on this form shall be available.

2.6 *Form 9–1870—Semi-Annual Gas-Well-Test Report.* All information contained on this form shall be available.

2.7 *Multi-point Back-Pressure-Test Report.* All information contained on this form shall be available.

2.8 *Sales of Lease Production.* Information contained on the monthly U.S. Geological Survey computer printout showing sales volumes, value, and royalty on production of oil, condensate, gas, and liquid products by lease shall be made available.

2.9 *Availability of Inspection Records.* All accident-investigation reports, pollution-incident reports, facilities-inspection data, and records of enforcement actions are also available for public inspection.

2.10 *Availability of Data and Information Submitted by Lessees.* It has been determined that much information submitted by lessees, as a result of OCS Orders and OCS Notices to Lessees and Operators, is nonproprietary in nature or that release of such information is necessary for the proper development of the lease. This information will be made available for public inspection, except for those portions which the lessee shall designate, with the Supervisor's approval, as trade secrets and commercial or financial information which is privileged or confidential. The available information will include:

a. Notices of support activity.

b. Oceanographic and meteorological data collected from drilling units and production facilities during the period of operations.

c. Results of site surveys required prior to drilling or placement of platforms or structures, such as shallow geologic hazard surveys, archeological/cultural resource surveys, or other surveys related to the placement of platforms or structures.

d. Drawings, maximum environmental design criteria, and rated capability data of mobile drilling units and structures.

e. Oil Spill Contingency Plans.

f. Critical Operations and Curtailment Plans.

g. Other data required under 30 CFR 250.34.

2.11 *Expired Leases.* All information is available upon the expiration of a lease.

3. *Information Exempt from Public Inspection.* The information in subparagraphs 2.1 through 2.4 which has been restricted from public inspection is classified as geological and geophysical data. The release of this data is subject to the following restrictions.

3.1 *Leases Issued Prior to June 11, 1976.* For leases issued prior to June 11, 1976, the classified data is exempt from disclosure under exemption No. (9) of the Freedom of Information Act [5 U.S.C. § 552(b)(9) and 43 CFR 2.13 subsection (c), *"Statutory Exemptions." (9)].*

3.2 *Leases Issued After June 11, 1976.* For leases issued after June 11, 1976, the classified data is available in accordance with 30 CFR 250.97, *Public Inspection of Records,* as follows:

a. *Geophysical Data.* Geophysical data shall not be available for public inspection, except as provided in 2.10c, without consent of the lessee as long as the lease remains in effect or for a period of 10 years after the date of submission, whichever is less, unless the Supervisor, with the approval of the Director, determines that earlier release of this information is necessary for proper development of the field or area.

b. *Geological Data.* Geological data shall not be made available for public inspection without the consent of the lessee as long as the lease remains in effect or for a period of 2 years after the date of submission, whichever is less, unless the Supervisor, with the approval of the Director, determines that earlier release fo such information is necessary for the proper development of the field or area. In accordance with 30 CFR 250.38, *Well Records,* data and well records shall be transmitted to the Supervisor upon request or, if not requested, within 30 days following completion or suspension of any well. For the purpose of orderly release of data, in all cases the date of submission will be considered to be 30 days following such completion or suspension.

4. *Departures.* All departures from the requirements specified in this Order shall be subject to approval, pursuant to 30 CFR 250.12(b).

Approved:

Don E. Kash,

Chief, Conservation Division.

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